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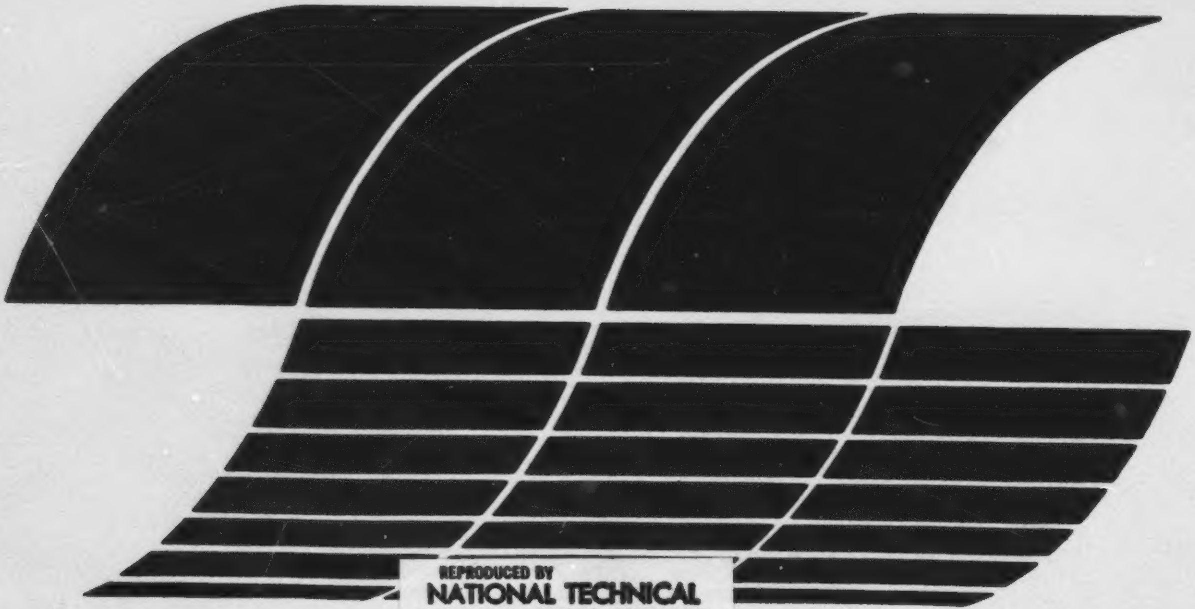

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March 1979

Applicability of the Thermal DeNO$_x$ Process to Coal-fired Utility Boilers

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FOREWORD

Two studies relating to Exxon's Thermal $DeNO_x$ Process for control of NO_x emissions from utility boilers have been sponsored by EPA/IERL-RTP. One, conducted by Exxon Research and Engineering Company under EPA Contract 68-02-2649, is entitled "Applicability of the Thermal $DeNO_x$ Process to Coal-fired Utility Boilers." The final report number is EPA-600/7-79-079, March 1979. The other, conducted by Acurex Corporation under EPA Contract 68-02-2611, is entitled "Technical Assessment of Exxon's Thermal $DeNO_x$ Process." Its final report number is EPA-600/7-79-111, May 1979.

The Exxon-prepared report discusses the Process background, engineering considerations, and cost estimates for application of this technology for a number of boiler/fuel cases at various NO_x control levels. Results of recent pilot-scale tests with coal-firing, sponsored by Exxon and the Electric Power Research Institute, are included.

The Acurex-prepared report objectively critiques the Exxon findings and also addresses a variety of environmental, operational, and supply/demand considerations that are relevant to the Thermal $DeNO_x$ Process.

Together, these reports give a good overview of this technology. We recommend that both reports be obtained, and read, by those wishing to become better informed about the Thermal $DeNO_x$ Process.

JK Burchard

John K. Burchard
Director
IERL-RTP

ABSTRACT

This EPA-sponsored program was undertaken to project the probable performance of the Exxon Thermal $DeNO_x$ Process on selected, representative coal fired utility boilers and to determine if Thermal $DeNO_x$ is better suited to certain boiler types than others. Also, budget type cost estimates were prepared for Thermal $DeNO_x$ applied to these boilers. The non-catalytic Thermal $DeNO_x$ Process is based on selective reduction of NO_x with NH_3 in the gas phase. Thermal $DeNO_x$ has been commercially demonstrated on gas- and oil-fired boilers and process furnaces. A pilot scale test on a coal fired combustor produced results similar to those obtained with oil and gas firing.

In undertaking the study reported here, Exxon Research and Engineering Co. (ER&E), selected eight typical coal-fired utility boilers, representative of the nation's boiler population. The boilers were chosen to permit an evaluation of the Thermal $DeNO_x$ Process on different utility boiler sizes, firing methods and coal types. Thermal $DeNO_x$ performance and process costs were determined for two NO_x reduction targets:

a. Trimming NO_x emissions to meet the proposed New Source Performance Standards (NSPS) of 0.6 lb. NO_x/MBtu* (450 ppm NO_x**) for bituminous coal and lignite fired boilers and 0.5 lb. NO_x/MBtu (375 ppm NO_x) for boilers fired with subbituminous coal.

b. Deep reduction in NO_x levels to 0.4 lb./MBtu (300 ppm NO_x) for boilers fired with bituminous coal and lignite and 0.3 lb. NO_x/MBtu (225 ppm) for subbituminous coal fired boilers.

Also considered was the:

c. Maximum practical reduction in NO_x levels which could be realized by the application of the Exxon Thermal $DeNO_x$ Process.

Two initial NO_x levels were considered for each of the above NO_x targets: (i) uncontrolled and (ii) reduced by combustion modifications. Each boiler was assumed to be equipped with two ammonia injection grids to permit load

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*Certain English units, have been used in this report. A table has been provided to facilitate conversion to the SI system.

**Throughout this report volumetric concentrations of NO_x are expressed as parts per million corrected to 3% O_2, dry basis.

following. In addition to the six cases, special analyses were performed for flue gas temperature nonuniformity and the use of hydrogen with ammonia to permit load following. A Performance Prediction Procedure developed by ER&E was used to project Thermal DeNO$_x$ performance. Also, the Thermal DeNO$_x$ costs for reaching NO$_x$ levels of 0.3 to 0.4 lb/MBtu were compared with the costs of combustion modifications (CM) required to reach these levels.

All eight units studied were projected to reach the proposed NSPS using Thermal DeNO$_x$ alone. Five of these units could reach this level using CM alone. All units except a cyclone boiler firing lignite were projected to reach the deep NO$_x$ reduction target when Thermal DeNO$_x$ was used with CM. Four boilers were projected to reach the deep reduction target using Thermal DeNO$_x$ alone. The Thermal DeNO$_x$ process costs to reach the proposed NSPS from an uncontrolled base level ranged from 0.25 to 1.17 mills/KW-Hr. The costs to reach the deep reduction target using Thermal DeNO$_x$ with CM ranged from 0.38 to 0.51 mills/KW-Hr and averaged 0.45 mills/KW-Hr for the seven boilers reaching the target. NO$_x$ reductions from uncontrolled initial levels ranging from 50 to 59% and costs ranging from 0.57 to 1.23 mills/KW-Hr were projected using Thermal DeNO$_x$ at a maximum practical level without CM. With CM, reductions ranging from 62 to 76% were projected. Costs ranging from 0.55 to 1.14 mills/KW-Hr were projected for the eight boilers studied.

The Thermal DeNO$_x$ Process was projected to be equally amenable to all units studied. One overall judgement criteria of performance, ammonia reagent costs/pound of NO$_x$ removed, were nearly equal for all units at 0.09 $/lb ΔNO$_x$. Conventional CM which could reach NO$_x$ levels of 0.3 to 0.4 lb/MBtu were cheaper than Thermal DeNO$_x$, but extreme CM such as derating were more expensive.

Thermal DeNO$_x$ performance is a function of the cross sectional temperature throughout the reaction zone. The Performance Prediction Procedure used assumes that a range of temperatures is present in the plane of the injection grid. This temperature range is assumed to be gradually smoothed out downstream of the injection location. It was projected that the ammonia injection grid location would not be affected significantly by assuming a 50°C larger temperature range in the injection plane than that used for baseline calculations. However, a temperature range increase of this size would reduce DeNO$_x$ performance by 5 to 10 percentage points (e.g., from 50% to 40-45%).

Hydrogen can be used with ammonia to lower the temperature at which the Thermal DeNO$_x$ reaction occurs. Thus, in certain cases it may be technologically possible to utilize ammonia plus hydrogen rather than dual grids to permit effective DeNO$_x$ performance at less than full boiler loads. In one such example considered, the use of hydrogen and ammonia fed through one grid increased the costs of Thermal DeNO$_x$ relative to the corresponding ammonia-only, dual grid cases considered.

The pilot plant scale test on coal firing noted earlier was sponsored jointly by Exxon Research and Engineering Co. and by the Electric Power Research Institute. The work was performed by KVB Inc. and their report is included here as Appendix 2.

A full scale test of the Exxon Thermal DeNO$_x$ Process on a coal fired utility boiler is recommended. This demonstration would be structured to evaluate ammonia breakthrough and DeNO$_x$ performance as a function of load, the effect of slag formation and fouling on Thermal DeNO$_x$ performance, the formation, deposition and removal of ammonium sulfates, the effect of ammonium sulfates on electrostatic precipitator performance, the influence of Thermal DeNO$_x$ on particulates, and other pollutants, and the compatibility of Thermal DeNO$_x$ system elements with coal ash levels and soot blowing equipment and procedures.

This report was submitted in fulfillment of Contract No. 68-02-2649 by Exxon Research and Engineering Company under the sponsorship of the U.S. Environmental Protection Agency. This report covers a period from September 30, 1977 to May 31, 1978, when the work was completed.

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16. ABSTRACT The report gives a projection of the performance and cost of the Exxon Thermal DeNOx Process applied to coal-fired utility boilers. Eight units were selected, representing different boiler manufacturers, sizes, firing methods, and coal types. Thermal DeNOx performance was projected both with and without combustion modifications for all boilers at full load and at one or more loads down to 50%. Three NOx reduction targets were used: the proposed New Source Performance Standards (NSPS), reduction to about two-thirds of the proposed NSPS, and the maximum practical NOx reduction that could be achieved. All costs are for full load. Thermal DeNOx was projected to be equally applicable for all boilers studied, despite significant differences in flue gas temperatures and flow paths. Maximum Thermal DeNOx performance ranged from 50 to 59% for the boilers studied. Costs ranged from 0.25 to 1.23 mills/kWh, excluding preliminary engineering costs and licensing royalties. A full-scale demonstration of Thermal DeNOx on a coal-fired utility boiler is recommended, including investigation of potential downstream effects of the process.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Ammonia	Stationary Sources	07B
Performance	NH3 Injection	14B
Cost Estimates	Thermal DeNOx Process	05A,14A
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CONVERSION FACTORS

To Convert From	To	Multiply By
lb/Hr	kg/Hr	0.4536
lb/MBtu	ng/J	430
ppm NO_x	mg/m^3	1.88*

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*NO_x expressed as NO_2 at 25°C

ACKNOWLEDGMENT

The authors acknowledge with thanks the boiler manufacturers, Babcock and Wilcox, Combustion Engineering, Inc., Foster Wheeler Corp., and Riley Stoker Corp., for providing technical information on their boilers required for undertaking this study.

SECTION 1

INTRODUCTION

Exxon Research and Engineering Company has developed a new process called Thermal DeNO$_x$ for reducing emissions of oxides of nitrogen from large stationary combustion sources. This non-catalytic process is based on the selective reduction of NO$_x$ with NH$_3$ in the homogeneous gas phase (1,2). The Thermal DeNO$_x$ process has been commercially demonstrated on gas- and oil-fired steam boilers and process furnaces. Exxon Research and Engineering Company has granted licenses on this process in Japan where NO$_x$ emission regulations are very stringent and in the U.S. where a test was recently completed on a boiler used for the enhanced recovery of oil. A test has also been performed on a pilot scale coal fired boiler.

The Thermal DeNO$_x$ process involves the injection of ammonia into the hot flue gas within a narrow and critical temperature range. Maximum NO$_x$ reductions ranging from 35% to 65% have been obtained with Thermal DeNO$_x$ on commercial units. Although the temperature sensitivity will cause the reaction's effectiveness to vary from one installation to another, the NO$_x$ reduction is essentially independent of the concentration of oxides of sulfur or particulate matter in the flue gas. The specific level achievable is dependent upon a number of factors, including the boiler design, operating mode, and initial NO$_x$ level.

Thermal DeNO$_x$ may be applied to boilers for additional NO$_x$ reduction after combustion modifications such as low excess air firing, the use of low NO$_x$ burners or overfire air ports have been implemented. As Thermal DeNO$_x$ is a post-flame injection process, it is not affected by certain limitations such as derating imposed on combustion modifications that may affect the usefulness of combustion modification in retrofit applications. Thus, the Thermal DeNO$_x$ process is viewed as an effective supplement to available combustion modification techniques for attaining low NO$_x$ levels for combustion installations that require a high degree of emission control.

The purpose of this EPA-sponsored program has been to project the performance and formulate budget type cost estimates of the Exxon Thermal DeNO$_x$ Process applied to a broad range of typical coal fired utility boilers. Exxon Research has undertaken an assessment of utility boiler types to determine if certain boilers as a function of firing method, size, or manufacturer's design are more amenable to the Thermal DeNO$_x$ Process than others. To perform this analysis, Exxon Research identified eight representative utility boiler categories which included one or more from each of the four major boiler manufacturers. These boilers were selected so as to permit an assessment of different utility boiler sizes. firing methods and coal types. In undertaking this assessment, Exxon Research consulted with and obtained from the four major U.S. utility boiler manufacturers the temperature, dimensions, flue gas flow and other non-proprietary boiler design information required to undertake this assessment. Exxon Research has also prepared budget type cost estimates of the Thermal DeNO$_x$ Process applied to the boilers considered.

Two key NO$_x$ reduction targets were formulated in undertaking the amenability analysis and cost estimates noted here. These were:

a. Trimming NO$_x$ emissions to meet the proposed New Source Performance Standards (NSPS) of 0.6 lb. NO$_x$/MBtu (450 ppm NO$_x$) for bituminous coal and lignite fired boilers and 0.5 lb. NO$_x$/MBtu (375 [illegible] NO$_x$) for boilers fired with subbituminous coal.

b. Deep reduction in NO$_x$ levels to 0.4 lb./MBtu (300 ppm NO$_x$) for boilers fired with bituminous coal and lignite and 0.3 lb. NO$_x$/MBtu (225 ppm) for subbituminous coal fired boilers.

Also considered was the:

c. Maximum practical reduction in NO$_x$ levels which could be realized by the application of the Exxon Thermal DeNO$_x$ Process.

Two initial NO$_x$ levels were considered for each of the above NO$_x$ targets: (i) uncontrolled and (ii) reduced by combustion modifications. Thus, a total of 6 cases were established. This permitted a thorough evaluation of the ability of the Thermal DeNO$_x$ Process to meet NO$_x$ target levels and to establish a range of costs where practical.

In addition to the above six cases considered for all boilers, two additional special analyses were performed for one boiler. One was a temperature nonuniformity sensitivity study and the other studied the use of hydrogen along with ammonia to achieve NO$_x$ reduction at reduced boiler loads. The former was prepared because of the significant temperature dependence of the Thermal DeNOx Process and the large temperature nonuniformity encountered in boiler flue gases. The latter was undertaken to illustrate the functioning and costs of the Thermal DeNO$_x$ system when hydrogen is used to accommodate load variations. An analysis comparing the cost of Thermal DeNO$_x$ with the costs of extreme combustion modifications in reaching NO$_x$ levels for the 0.3 to 0.4 lb. NO$_x$/MBtu range was undertaken. The limited availability of costs for combustion modifications for reaching this NO$_x$ target level limited the scope of this comparison.

The following sections present the conclusions reached and our recommendations for future work. This is followed by general background information concerning the Exxon Thermal DeNO$_x$ Process including process chemistry, engineering considerations, process costs and commercial scale experience.

After the Process Background discussion is a section which provides Program Detail including the boilers selected for study, initial and final DeNO$_x$ reduction levels and cases evaluated, as well as information on the performance prediction procedure used and the assumptions involved in cost estimation. This is followed by a results section which provides the results and conclusions of the six general cases studied plus results of the temperature nonuniformity study and the hydrogen addition case. Cost data generated on this program is presented in Appendix I. A report covering the pilot plant scale test on coal firing, sponsored jointly by Exxon Research and Engineering Company and the Electric Power Research Institute is presented as Appendix 2. The work was performed by KVB Inc. which has also authored the coal study report.

SECTION 2

CONCLUSIONS

The performance of the Exxon Thermal DeNO$_x$ process was projected to be essectially equivalent for all eight boiler types evaluated, even though significant differences existed in flue gas temperature profiles and flow path configurations among boilers. These differences resulted in the selection of significantly different injection grid locations among the boilers of different manufacturers. The analysis determined that the proposed NSPS of 0.5 lb./MBtu for subbituminous coal and 0.6 lb./MBtu for lignite and bituminous coal could be met by all boilers considered using the Thermal DeNO$_x$ Process. All boilers studied, except the cyclone boiler fired with lignite, could meet the deep reduction targets of 0.3 and 0.4 lb./MBtu using Thermal DeNO$_x$ coupled with presently available combustion modifications.

It was projected that the ammonia injection grid location would not be effected significantly by assuming a 50°C larger temperature range in the injection plane than that used for baseline calculations. However, a temperature range increase of this size would reduce DeNO$_x$ performance by 5 to 10 percentage points (e.g. from 50% to 40-45%). It was also found that overall NO$_x$ removal costs increased when hydrogen (rather than multiple grids) was used with only one grid to achieve effective DeNO$_x$ performance at other than full boiler loads.

Other specific projections and conclusions were as follows:

- All units could reach the proposed NO$_x$ NSPS using Thermal DeNO$_x$ alone. Five of the eight units studied could also reach this level using combustion modifications alone.
- All units except one could meet the deep NO$_x$ reduction target when Thermal DeNO$_x$ was used in combination with combustion modifications. The one exception was the cyclone boiler fired with lignite.
- Projected costs to reach the proposed NSPS from an uncontrolled base level ranged from 0.25 mills/KW-Hr for the 250 MW CE boiler to a high of 1.17 mills/KW-Hr for the lignite fired cyclone boiler. The average cost for all boilers considered was 0.57 mills/KW-Hr, or 0.49 mills/KW-Hr not including the cyclone boiler.

- Four of the eight boilers could reach the deep reduction target using Thermal DeNO$_x$ alone. Costs ranged from 0.38 mills/KW-Hr to 0.83 mills/KW-Hr for these boilers.

- Projected costs to reach the deep reduction target using Thermal DeNO$_x$ with combusiton modifications ranged from 0.38 mills/KW-Hr to 0.51 mills/KW-Hr, with the average being 0.44 mills/KW-Hr for the seven boilers reaching the target level.

- NO$_x$ reductions ranging from 62% to 76% and averaging 70% relative to an uncontrolled base case could be achieved using Thermal DeNO$_x$ at a maximum practical level in combination with combustion modifications. NO$_x$ levels in the 0.20 to 0.23 lb. NO$_x$/MBtu range could be realized for most of the boilers. Costs ranged from 0.55 to 1.14 mills/KW-Hr and averaged 0.68 mills/KW-Hr for all boilers studied. With the lignite boiler excluded, the range was 0.55 to 0.67 mills/KW-Hr and the average was 0.61 mills/KW-Hr.

- The costs for onsites and the carrier were found to be proportional to boiler size.

- The total ammonia reagent costs for all cases, normalized for the amount of NO$_x$ removed expressed as NO$_2$ (ΔNO_x), were nearly equal for all eight units studied at \$0.09/lb. ΔNO_x. This parameter was considered to be a good overall judgment criterion of the chemical efficiency and economic efficacy of the Thermal DeNO$_x$ process.

- The Exxon Thermal DeNO$_x$ Process was considered to be equally amenable to all units studied.

- The costs for reaching NO$_x$ levels in the 0.3 to 0.4 lb./MBtu range were compared for Thermal DeNO$_x$ and combustion modification. The costs of most conventional combustion modifications and combinations thereof were lower than that of Thermal DeNO$_x$. Extreme NO$_x$ reduction methods such as derating or staged combustion that incurred derating would be more expensive. Derating would not generally be used as a NO$_x$ reduction technique.

SECTION 3

RECOMMENDATIONS

The primary recommendation resulting from this study is that the Exxon Thermal DeNO$_x$ Process be tested on a coal fired utility boiler. The boilers of the four major utility boiler manufacturers have been found to be approximately equally amenable to the Thermal DeNO$_x$ Process. After the selection of an appropriate candidate boiler, the same type of performance and cost analyses presented here must be prepared. Temperature and velocity profile measurements in the boiler heat transfer region are then required to verify grid placement and performance estimates. After installation and startup of the Thermal DeNO$_x$ system a careful measurement and evaluation program will be needed to assess DeNO$_x$ performance, cost and determine any possible side effects which result from the use of the Thermal DeNO$_x$ Process.

In undertaking this demonstration, a high level of attention should be accorded to those factors which could reduce the overall effectiveness of the Thermal DeNO$_x$ Process on coal fired utility boilers, or could have adverse side effects on boiler operation or the environment. These factors include:

- Ammonia and by-product emissions
- Effect of slag formation and fouling on DeNO$_x$ reaction zone temperatures, and on resulting DeNO$_x$ performance.
- Effective DeNO$_x$ performance under differing boiler load conditions.
- Effect of deposition of ammonium sulfates on metal surfaces and on electrostatic precipitator performance.
- Compatibility of Thermal DeNO$_x$ system elements with coal ash levels and with soot blowing equipment and procedures.

SECTION 4

PROCESS BACKGROUND

This section provides general backgound information on the Exxon Thermal DeNO$_x$ Process. Presented is information on the chemistry of the process, engineering considerations, process costs discussed in general terms and a brief summary of commercial scale experience.

CHEMISTRY OF THE PROCESS

The process chemistry relies on the selective reaction between NH_3 and NO_x to produce nitrogen and water. The reaction requires the presence of oxygen and proceeds within a critical temperature range. The overall NO reduction and production reactions are summarized in equations (1) and (2), respectively:

$$NO + NH_3 + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O \qquad (1)$$

$$NH_3 + 5/4\ O_2 \rightarrow NO + 3/2\ H_2O \qquad (2)$$

In typical flue gas environments, the NO_x reduction shown as equation (1) dominates at temperatures around 950°C (1740°F). At higher temperatures, the NO_x production reaction shown as equation (2) becomes significant, and it dominates at temperatures over about 1000°C (1830°F). As temperatures are reduced below about 900°C (1650°F), the rates of both reactions slow, and the ammonia flows through unreacted.

The following chain reaction cycle was proposed by Dr. R. K. Lyon of Exxon Research for the NH_3-NO-O_2 reaction system (2):

$$NH_2 + NO \rightarrow N_2 + H + OH \qquad (3)$$

$$NH_2 + NO \rightarrow N_2 + H_2O \qquad (4)$$

$$H + O_2 \rightarrow OH + O \qquad (5)$$

$$O + NH_3 \rightarrow OH + NH_2 \qquad (6)$$

$$OH + NH_3 \rightarrow H_2O + NH_2 \qquad (7)$$

$$H + NH_3 \rightarrow H_2 + NH_2 \qquad (8)$$

This chain reaction mechanism is sufficient to explain qualitatively the observed reduction of NO by NH_3 in the presence of O_2.

In practice, ammonia is injected into either boiler cavities or tube banks or both. Exxon has shown that in certain applications the practical, working potential of the Thermal $DeNO_x$ Process under varying loads and NO_x levels can be achieved through ammonia injection alone. Exxon Research has found that hydrogen can be used to shift the $DeNO_x$ temperature window to lower levels. The magnitude of this shift is mainly a function of the amount of H_2 injected relative to the NH_3. At H_2/NH_3 ratios on the order of 2:1, the NO_x reduction reaction can be forced to proceed rapidly at 700°C (1290°F). By judiciously selecting the H_2/NH_3 injection ratio, flue gas treatment can be accomplished over the range of 700-1000°C.

In addition to temperature, the process is also sensitive to initial NO_x and NH_3 concentrations. The NH_3 injection rate is generally expressed as a mole ratio relative to the initial NO_x concentration. Other variables affecting performance are excess oxygen and available residence time at the reaction temperature.

The issue of possible pollutant by-products (HCN, N_2O, CO, SO_3 and NH_4HSO_4) has been addressed by Exxon Research studies. Hydrogen cyanide can be produced only if hydrocarbons are present in the Thermal $DeNO_x$ reaction zone. Under normal conditions, hydrocarbons are absent from this zone. As regards N_2O production, it represents only one to two percent of the NO_x reduced. The Thermal $DeNO_x$ Process does not generate CO by reducing CO_2. However, CO oxidation is inhibited by NH_3, so that if CO is present, it would be emitted unreacted into the atmosphere. This effect is of no consequence under normal operating conditions for most boilers, as CO oxidation is complete before the NH_3 injection point.

Detailed laboratory experiments have shown no interaction between the Thermal $DeNO_x$ Process and sulfur compounds in the high temperature flue gas regions. That is, sulfur or its oxides do not interfere with the NH_3-NO_x-O_2-H_2 chemistry. Additionally, ammonia injection has been shown to cause neither additional homogeneous nor additional heterogeneous oxidation of SO_2 to SO_3.

To the extent that the thermal reduction of NO leaves some NH_3 unreacted, and as the combustion gases cool, NH_3 can react with SO_3 and H_2O to form ammonium sulfates. Ammonium bisulfate is a viscous liquid at air heater temperatures. Based on laboratory and commercial tests, these sulfates do not appear to create either severe corrosion or unacceptable air heater fouling problems when Thermal $DeNO_x$ is used in accordance with its design specifications. Long term tests conducted in two oil-fired boilers by Tonen Sekiyu Kagaku K.K. in Kawasaki, Japan, revealed these highly water-soluble deposits could be removed by waterwashing the air heaters. Although long term data are very limited, the frequency of waterwashing in these Japanese installations approaches two to three times per year. Of course, only through a Thermal $DeNO_x$ demonstration on a coal fired boiler can the washing requirement be quantified.

ENGINEERING CONSIDERATIONS

When applying the Thermal DeNO$_x$ Process to commercial equipment, performance is generally limited by the extreme temperature sensitivity of the reaction and its dependence on the local concentrations of reactants, NH$_3$, NO$_x$, O$_2$ and H$_2$. The Exxon technology provides a means of adapting the chemistry requirements to industrial equipment environments, and NO$_x$ reductions up to about 60% can be achieved by the use of Thermal DeNO$_x$ technology in existing boilers. Application to new, grass-roots designs is usually easier because the internal configuration of the high temperature zone can be adjusted to complement the process demands.

The Thermal DeNO$_x$ Process utilizes proprietary Exxon gas phase mixing technology to rapidly and efficiently mix the small volume of reagents with the hot flue gas. Correct distribution of reactants is required because of non-linearities in the reaction rates. Locally high concentrations of NH$_3$ will decrease the maximum attainable NO$_x$ reduction and will also result in the breakthrough of unreacted ammonia.

Accommodating flue gas temperature varations is important if high DeNO$_x$ rates are to be achieved. Not only does the system have to accommodate flue gas temperature changes caused by normal load and operating variations, but it also must allow for fluctuations across the reaction zone caused by non-uniformities in flow and heat transfer. It follows, therefore, that a case-by-case evaluation of flue gas temperatures and local conditions is required for the application of Thermal DeNO$_x$ for each installation considered.

Initially, ammonia was injected only into boiler cavities, boiler regions between tube banks, which can be considered to be isothermal to a first approximation. Subsequent experimentation by Exxon Research has shown the feasibility of injecting ammonia into boiler tube bank regions as well. Thus, satisfactory NO$_x$ reduction performance can be obtained by locating the injector grid in either the boiler cavity or tube bank. The ability to inject ammonia at virtually any post-combustion boiler location where temperatures range from 760°C to 1000°C has substantially increased the flexibility of the Exxon Thermal DeNO$_x$ process.

The temperature in the post-combustion zone of a boiler can be shifted by changes in boiler load. For example, as load is reduced from full to 50%, the temperature for optimum Thermal DeNO$_x$ will shift toward the fire box. Depending on the magnitude of this shift, more than one ammonia injection grid may be required in order to obtain DeNO$_x$ coverage over the range of practical boiler loads. Thus, one grid may be adequate for boiler loads between 100% and 70% while another would cover the 70 to 50% load range. It must be noted, however, that the use of hydrogen with its ability to lower the effective DeNO$_x$ temperature window could permit effective DeNO$_x$ over practical boiler loads with only one grid. In other cases, both hydrogen addition and the use of multiple grids may be required to accommodate load changes. A specific case was considered in which the costs of a single grid ammonia-hydrogen system were compared with the costs of dual grids used with ammonia alone.

PROCESS COSTS

The costs associated with the Thermal DeNO$_x$ Process are sensitive to the particular circumstances of the application. Factors influencing cost include initial NO$_x$ concentration, reduction target, compatibility of the boiler design and operation, and local price and availability of chemicals and utilities.

As an example, consider applying the process to a 300 MWe oil-fired utility plant with an initial NO$_x$ level of 225 ppm (about 0.3 lb. NO$_x$/M Btu fired). Assume the boiler geometry and operating conditions provide a temperature in the reaction zone which does not require H_2, and that for a 50% NO$_x$ reduction target, an approximate NH_3/NO_x injection ratio of 1.0/1 is feasible. Thus, Thermal DeNO$_x$ will have the following estimated operating costs:

(a) NH_3 @ 1.0 mole per mole NO$_x$ (assume 170 \$/ton) = 0.9 ¢/M Btu

(b) Utility air @ 210 SCF per M Btu fired (assume 0.005 ¢/SCF, including compressor cost) = 1.0 ¢/M Btu

The total operating cost is estimated at 1.9 ¢/M Btu or about 0.19 mills/KW-Hr assuming a heat rate of 10,000 Btu/KW-Hr.

Note that 20 psig utility air is used as a diluent in the injection system. An alternative approach would be to use a similar quantity of low pressure steam, resulting in a different operating cost. The availability of reagents and utilities usually represent the greatest variable in the installation cost. In situations where such facilities are already available on site, the equivalent cost for capital investment for a large utility boiler can be lowered.

The equivalent cost for the above example totals about 2.9 ¢/M Btu fired. With the assumed reduction of NO$_x$ emissions from 225 to 112 ppm, the cost-effectiveness is about 390 \$/ton of NO$_x$ removed (expressed as NO_2). As previously stated, total cost and effectiveness will vary for other cases depending on both technical and economic factors. Where higher DeNO$_x$ severities are required, or where optimum flue gas temperatures are not available, H_2 and higher NH_3/NO_x ratios would be required, thus significantly increasing overall cost.

COMMERCIAL SCALE EXPERIENCE

Thermal DeNO$_x$ has been demonstrated in twelve commercial boilers and furnaces to date. Actual capability often represents a compromise between the technical limits of the process chemistry and cost-effectiveness. In many situations, performance is maximized at full load operation, and smaller NO$_x$ reductions are accepted at reduced loads that result in lower reaction zone temperatures. In such installations, total NO$_x$ emissions are generally at target levels over the full range of operating conditions because of the reduced NO_x production at lower loads. Results from six demonstrations are shown over their range of operating conditions as a function of flue gas temperature in Figure 4-1. Hydrogen was used along with ammonia to obtain most of the data shown in Figure 4-1.

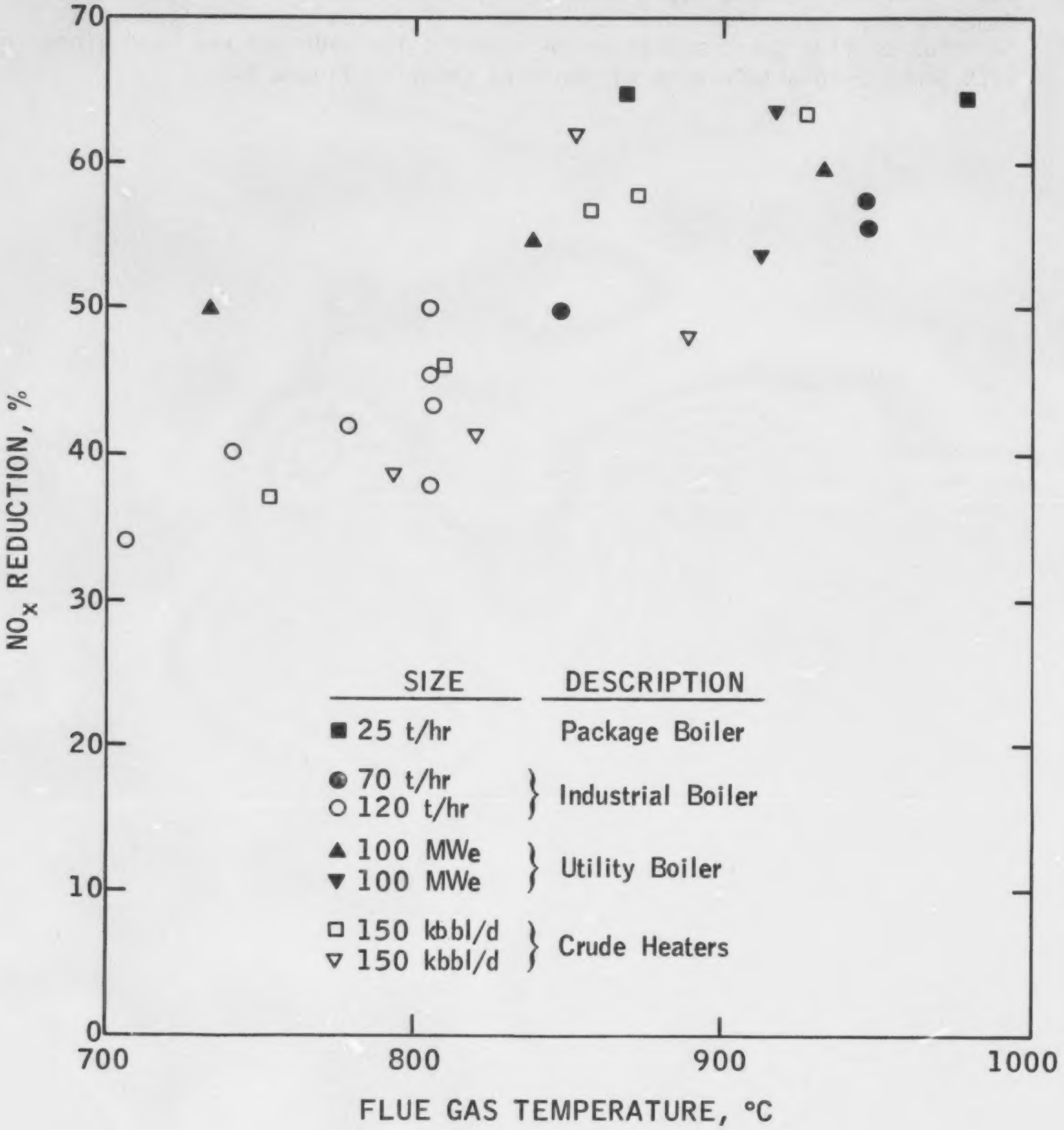

Figure 4-1 Performance of Thermal $DeNO_x$ systems in commercial applications.

SECTION 5

PROGRAM DETAIL

This section provides information regarding the boilers selected for study in this program. The NO_x reduction cases are discussed, and the initial and final NO_x levels for each case are noted. Also provided is information on the Thermal $DeNO_x$ Performance Prediction Procedure utilized in determining the effectiveness of the Thermal $DeNO_x$ Process in each case studied. The assumptions used for formulating the cost estimates for the Thermal $DeNO_x$ Process are noted and other cost estimation information is provided for the Thermal $DeNO_x$ process as well as for combustion modifications.

BOILERS SELECTED FOR STUDY

This EPA-sponsored analysis has determined the applicability of Thermal $DeNO_x$ to representative coal fired boilers of different manufacturers, firing types, boiler sizes and coal types. The boilers/sizes/firing types selected for study are shown in Table 5-1.

The boilers selected were within their size ranges among the most commonly occurring in the U.S. power generation industry. Four of the boilers fire bituminous coal, three subbituminous, and one lignite. One or more boilers from each major boiler manufacturer has been considered. One boiler in the 330-350 MW range from each manufacturer has been studied.

NO_x REDUCTION CASES

This subsection notes the two sets of final NO_x target levels which were used as well as the two initial NO_x levels which were assumed for baseline-uncontrolled operation and for combustion modifications. The four resulting cases plus two additional cases for maximum practical NO_x reduction are also noted.

Final NO_x Levels

Two sets of final NO_x reduction levels or targets were selected for this study. One group included a trim to the proposed New Source Performance Standards (NSPS). The other, a deeper reduction to low levels of NO_x.

The proposed NSPS for NO_x from coal firing are categorized by coal type. These standards are shown below in both lbs./MBtu and in ppm. In this case, the conversion used was NO_x, lbs./MBtu = ppm NO_x (@ 3% O_2) x 0.00133 (4,5).

TABLE 5-1. BOILERS SELECTED FOR STUDY

Boiler Manufacturer	Boiler Type	Boiler Size, MW	Coal Type
Babcock and Wilcox	Front Wall	130	Subbituminous
Babcock and Wilcox	Horizontally Opposed	333	Bituminous
Babcock and Wilcox	Cyclone	400	Lignite
Combustion Engineering	Tangential Single Furnace	350	Bituminous
Combustion Engineering	Tangential	800	Subbituminous
Foster Wheeler	Front Wall	330	Bituminous
Foster Wheeler	Horizontally Opposed	670	Subbituminous
Riley Stoker	Turbo Furnace	350	Bituminous

Proposed NSPS

Coal Type	lbs./MBtu	ppm
Bituminous	0.6	450
Subbituminous	0.5	375
Lignite*	0.6	450

- - - - - - -

* The proposed standard for cyclone firing of North and South Dakota and Montana Lignite is 0.8 lbs/MBtu (600 ppm). This specific case will not be considered here.

The final NO_x targets were selected to provide an assessment of Thermal $DeNO_x$ performance capabilities and represent a deep reduction in NO_x emission levels. These NO_x levels were also assumed to be a function of the coal type burned and were:

Deep Reduction Targets

Coal Type	lbs./MBtu	ppm
Bituminous	0.4	300
Subbituminous	0.3	225
Lignite	0.4	300

Initial NO_x Levels

The initial NO_x levels utilized in undertaking this study were those which are characteristic of the selected types and sizes of boilers firing the coal types specified. Most of the initial values were derived from data obtained by Exxon Research and Engineering Company on the program "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Power Generation Combustion Systems" sponsored by EPA under Contract No. 68-02-1415 (4). Additional data were furnished by the boiler manufacturers.

NO_x levels were extrapolated for each boiler studied under (a) reduced load and (b) with the application of combustion modifications. In formulating these NO_x levels, two generalizations based on field test data (4) were utilized:

(1) Reducing load by 25% from full load lowers NO_x emissions by 10%. Reducing load by another 25%, to 50% load lowers NO_x emissions a total of 20% in ppm.

(2) The application of combustion modifications (CM) lowers NO_x emissions from an uncontrolled level by 40% at each load. CM are less effective than this on cyclone boilers. For the cyclone boiler studied, CM were assumed to reduce NO_x emissions by 10% from the base case at each load.

A variety of combustion modification techniques are available for most boiler types considered. These generally can be used individually or in combination to achieve the 40% NO_x reduction noted above. For example, low NO_x burners which are applicable to front wall and horizontally opposed fired boilers have been introduced relatively recently and Exxon Research has shown that 40% NO_x reductions are possible relative to an uncontrolled case in which conventional burners are used (4). Low excess air firing coupled with the staging of burners are two techniques also applicable to these boiler types. Low excess air firing can reduce NO_x emissions from cyclone fired boilers. Low excess air firing plus the use of overfire air ports are successful in reducing NO_x emissions with tangential firing, a combustion system which is inherently a low NO_x producer. Overfire air ports plus air vane direction can be used to reduce NO_x emissions in turbofurnace boilers.

Cases Established

As was noted above, one group of NO_x reduction levels include a trim to 450 ppm NO_x (for bituminous coal and lignite firing) and 375 ppm NO_x (subbituminous). These levels are the proposed NSPS levels for coal firing. For trimming, two cases arise:

Case 1: Combustion Modifications (CM) cannot be used and the intial NO_x level is the uncontrolled baseline NO_x level.

Case 2: CM can be used with the result that the initial NO_x levels would be reduced.

The other group of NO_x reduction levels specifies a deep reduction to 300 ppm (bituminous and lignite) and 225 ppm (subbituminous). Two additional cases arise:

Case 3: CM cannot be used.

Case 4: CM can be used thereby reducing the initial NO_x level.

As can be seen, the above define the best case and the worst case for the two general target NO_x levels. Thus, the estimates produced resulted in a range of costs rather than in one specific level of cost for the trim cases and for many of the deep reduction cases. This should be of greater utility than one specific cost level. (It might be argued that no boiler of the types considered here could be so inflexible as to be totally incapable of accommodating combustion modifications of some type. This is probably true. However, for this evaluation we assumed this worst case.) The actual NO_x levels investigated are shown in Table 5-2. This table illustrates that in certain cases, the target NO_x levels are achievable using combustion modifications alone.

In addition to these cases to establish a range of costs, two additional cases have been considered. These cases represent the maximum NO_x reduction that can be achieved on a practical basis with the Thermal $DeNO_x$ Process. (Grid placement is assumed to be the same as in the other cases studied.) The two new cases which can be formulated are:

Case 5: Maximum NO_x reduction attainable with an ammonia to initial NO_x molar ratio of 1.5.

Case 6: Maximum NO_x reduction attainable with $NH_3/NOI = 1.5$ with combustion modifications.

In both cases 5 and 6, the final NO_x levels attained may be either greater than or less than the target NO_x levels in the prior cases.

Cost estimates for NO_x reduction were performed for full load only.

TABLE 5-2. INITIAL AND FINAL NO$_x$ LEVELS FOR BOILER/COAL COMBINATIONS

Boiler				100% Load		75% Load		50% Load	
Manufacturer	Firing Method and Fuel	MW	Case	Initial	Final Target	Initial	Final Target	Initial	Final Target
B&W	FW Subbituminous	130	1	500	375	450	375	400	375
			2	300	375*	270	375*	240	375*
			3	500	225**	450	225	400	225
			4	300	225	270	225	240	225*
B&W	HO Bituminous	333	1	700	450	630	450	560	450
			2	420	450*	380	450*	340	450*
			3	700	300**	630	300**	560	300
			4	420	300	380	300	340	300
B&W	Cyclone Lignite	400	1	1000	450**	900	450	800	450
			2	900	450	810	450	720	450
			3	1000	300**	900	300**	800	300**
			4	900	300**	810	300**	720	300**
CE	T-Single Furnace Bituminous	350	1	500	450	450	450*	400	450*
			2	450	450*	400	450*	360	450*
			3	500	300	450	300	400	300
			4	450	300	400	300	360	300
CE	T-Twin Furnace Subbituminous	800	1	530	375	480	375	425	375
			2	375	375*	340	375*	300	375*
			3	530	225**	480	225**	425	225
			4	375	225	340	225	300	225
FW	FW Bituminous	330	1	850	450	770	450	680	450
			2	510	450	460	450*	410	450*
			3	850	300**	770	300**	680	300**
			4	510	300	460	300	410	300
FW	HO Subbituminous	670	1	700	375	630	375	560	375
			2	420	375	380	375*	340	375*
			3	700	225**	630	225**	560	225
			4	420	225	380	225	340	225
RS	Turbo Furnace Bituminous	350	1	700	450	630	450	560	450
			2	420	450*	380	450*	340	450*
			3	700	300**	630	300**	560	300
			4	420	300	380	300	340	300

* NO$_x$ level is either below the target level or can be reached using combustion modifications alone.

** NO$_x$ level cannot be reached with Thermal DeNO$_x$ alone, assuming 50% NO$_x$ reduction.

THERMAL DeNO$_x$ PERFORMANCE PREDICTION PROCEDURE

This section provides some background information on the Performance Prediction Procedure used to estimate the NO$_x$ reduction achievable using the specified initial NO$_x$ levels and final NO$_x$ targets. The sequence in applying the predictive procedure which leads up to the cost estimation steps is also discussed. This is followed by some of the assumptions used in undertaking the performance prediction.

The selection of the locations where ammonia will be injected is based on a number of factors which include: flue gas temperature and conditions, flow path geometry, the reaction time available and the suitability of the reaction zone with repect to its dimensions and configuration injector grid. A Performance Prediction Procedure developed by Exxon Research and Engineering Company was used to determine the locations of the ammonia injection grids.

The Exxon Performance Prediction Procedure is a multistep calculation procedure which utilizes and/or determines the above noted factors. The calculation procedure can forecast the percent reduction in initial NO$_x$ level which would result from the location of an ammonia injection grid at any number of locations along the flue gas path. The Performance Prediction Procedure is based on fundamentals combined with pilot and commercial scale experience. For this EPA-sponsored study program the required temperature and dimensional information were supplied by the boiler manufacturers. In the case of an actual installation, after the tentative selection of the location(s) of one or more grids using the Exxon procedure, an experimental program would be conducted to measure temperature, flow and concentration distributions in the reaction zone. This information would then be used to confirm or adjust as required the injector location selected and would be utilized as input for the final injector design.

The sequence of events in applying the Thermal DeNO$_x$ Performance Prediction Procedure leading up to the cost estimating steps is listed below.

1. The Exxon Thermal DeNO$_x$ Performance Prediction Procedure was applied using data supplied by the boiler manufacturers.

2. The effectiveness of the Thermal DeNO$_x$ process was determined for most boilers studied at 3 loads: 100%, 75%, and 50%. For each boiler and each load, two levels of NH_3 injection were considered. These levels were expressed as a molar ratio of NH_3 to the initial NO$_x$ level (NOI). The two levels possessed NH_3/NOI ratios of 1.5 and 1.0.

3. Two initial NO$_x$ levels (both with and without combustion modifications) were established from data obtained by Exxon Research and Engineering Company on the program, "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions From Power Generation Combustion Systems" sponsored by EPA under Contract No. 68-02-1415. Some additional data were supplied by the boiler manufacturers.

4. Two sets of final NO_x levels were utilized. These were: the proposed New Source Performance Standards (trimming case) and a deep reduction case. The use of two initial and two final NO_x levels permitted a range of costs to be established for certain boilers.

5. Two ammonia injection grid locations were selected for each boiler studied based on the results of the Performance Prediction Procedure. Thus, for each of the two grid locations, the percent NO_x reduction resulting from the use of two levels of NH_3 was determined.

6. For each grid location, a plot was made of percent NO_x reduction vs. NH_3/NOI molar ratio. The third point was assumed to be the origin, zero. Thus, for each boiler, two curves were generated, one for each of the two injector locations. Both lines terminated at the origin. From these plots the quantity of NH_3 required to reach the specified NO_x reduction target could be determined.

Some of the assumptions used in application of the Performance Prediction Procedure are noted below.*

1. There are two injector locations, one designed to serve two boiler loads, and the other to serve one load. The combination-load grid will operate for either the 50 percent/75 percent or the 75 percent/100 percent load combination, and the single load grid will operate for either the 50 percent or the 100 percent load.

2. The combination-load grid is located where the crossover of the performance curves is a maximum. The single-load grid is then located where the performance curve peaks for the remaining load. An exception was made for the CE boilers where the combination-load grid (50/75 percent load) was placed at the exit of the firebox, and the single-load grid (100 percent) was placed at the peak of the performance curve. For this screening study, performance calculations were done at the upstream boundary of each flue gas flow path segment and a smooth curve was drawn through the predicted points. The length of the cavity upstream of the first tube bank was set at 150 mm for the B&W 130 MW and B&W 400 MW boilers.

3. The carrier is air.

4. The carrier temperature is 80°C at the feed pipe entry point into the flue gas duct.

5. Flue gas pressure is 1 atmosphere.

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* Certain aspects of the Thermal $DeNO_x$ Performance Prediction Procedure are considered to be proprietary in nature and are not described in this report.

COST ESTIMATES

This section provides details of how the cost estimates in this program were performed. Provided is specific information regarding ammonia handling facilities, air compressors and the on-sites. The assumptions used in the estimation of Thermal DeNO$_x$ costs are noted as are details for the cost estimates formulated for combustion modifications.

Thermal DeNO$_x$ Cost Estimates

The cost estimates presented here are designed to illustrate the costs associated with the Thermal DeNO$_x$ Process itself. The techniques and procedures used in producing these cost estimates were the same as would be applied to a more completely defined project. In the cases considered here the projects were not completely specified with respect to a number of factors which could have an impact on costs. The Process was assumed retrofit-installed on eight typical representative coal fired utility boilers. It should, however, be realized that each candidate boiler for the Thermal DeNO$_x$ Process must be considered on an individual basis from both performance and cost viewpoints. In general, the costs presented here emphasize the costs of the Process itself. Certain costs which may be associated with the Process such as licensing fees and certain preliminary engineering and testing are not included.

Cost estimates were prepared for three individual elements of the DeNO$_x$ facilities: ammonia handling facilities, air compressors, and the "on-sites" which include the ammonia injection grids. The costs are presented as of the second quarter of 1977 and assume a U.S. Gulf coast location.

Costs for three sizes of ammonia handling facilities were estimated and the costs for intermediate sizes were interpolated. The three examples assumed ammonia consumption at the rates of: (Example 1) 330 lbs./hr., (2) 1000 lbs./hr., and (3) 3000 lbs./hr. Estimated were the costs of line sizes, drum sizes, pump sizes, etc. with all facilities being commensurate with the rated demand.

The first two examples assumed receipt of ammonia in pressurized tank trucks and the use of a single storage drum. Example 3 assumed receipt in pressurized rail cars and the use of three storage drums. The unloading pumps and lines were similar for all cases and the storage was sized for seven days. The ammonia storage drums were designed to operate with a minimum temperature of 50°F and were uninsulated. Ammonia vapor was assumed to be withdrawn from the storage drums at 90 psia and metered using up to twelve lines as dictated by the case in question.

The total breakdown in terms of material and labor is presented below in thousands of dollars for each case. To these costs were applied a total erected cost multiplier of 1.43 which includes field labor, overhead and burden. This value is based on our actual historical data for construction occurring on the U.S. Gulf Coast during the second quarter of 1977, the area and period selected for all cost estimates.

Example Number	1	2	3
Direct Material, k$	147	195	422
Direct Labor, k$	53	55	93
Total M&L, k$	200	250	515
Total Erected Cost, k$	286	358	736

As was noted above, the costs for intermediate sizes were interpolated from these total erected cost values.

The use of air as a carrier requires the installation of air compressors. For the same three examples noted above, sizes of compressors required were (1) 1000 SCFM, (2) 6000 SCFM and (3) 20,000 SCFM. Compressor costs were obtained from vendor quotes. Other material costs were associated with buildings, concrete, piping, structural steel, instruments, paint, etc. The breakdown in terms of direct labor expressed in thousands of dollars is presented below. Again, the total erected cost multiplier of 1.43 was applied to these values resulting in the total erected cost. Costs for intermediate sizes were interpolated from these cost values.

Example Number	1	2	3
Direct Material, k$	195	360	530
Direct Labor, k$	35	45	60
Total M&L, k$	230	405	590
Total Erected Cost, k$	330	580	843

The costs for on-site facilities ("onsites") including the costs of grids are based on our historical experience in the construction of such facilities.

The assumptions used in cost estimation are noted below:

1. Fixed costs are total erected costs, 2nd quarter 1977, U.S. Gulf Coast, no escalation and no contingency included.

2. Reagent fixed costs include NH_3 storage vessel, vaporizer, and piping.

3. Carrier fixed costs include air compressor and piping.

4. Onsite fixed costs include two injector grids, instrumentation and controls.

5. Operating costs are for $DeNO_x$ system operation at 100 percent load.

6. The NH_3/NOI ratio required to obtain a specified NO_x reduction is calculated by linear interpolation between the NH_3/NOI ratios of 1.5, 1.0 and the origin, 0. These point constituted the performance curve used. NH3/NOI = 1.5 is the maximum NH_3 rate considered. No extrapol-

ation to higher rates was performed. In practice, some molar ratios used were between 0 and 1.0 and other were between 1.0 and 1.5.

7. Calculated NH_3 consumptions are based on nominal initial NO_x levels and flue gas flow rates. No adjustments have been made for variations in excess air levels and flue gas moisture content.

8. Reagent operating cost is based on an NH_3 cost of $85.00 per 1000 lb.

9. Carrier rate for cost calculations has a maximum value of 1.5% of the flue gas rate. The total carrier rate is the sum of the operating grid rate and the rate used for cooling the idling grid.

10. Carrier operating costs are calculated as follows: Air compressor power requirements are 1100 HP (820.6 KW) per 10,000 SCFM. Electricity cost is 0.03 $/KW-Hr. Resulting carrier operating cost is $0.41 per 10,000 SCF.

11. Annual fixed charges are taken as 20% of investment. This figure includes finance costs and maintenance. Annual service factor is 80% of full load.

12. No licensing fees or royalties are included.

13. $/MW-Hr. is equivalent to mills/KW-Hr.
$/MW-Hr. = 10 times $/MBtu assuming a heat rate of 10,000 Btu/KW-Hr.

The equations used in undertaking the Thermal $DeNO_x$ cost estimates are shown in Table 5-3.

Combustion Modification Cost Estimates

The costs for combustion modifications were derived from information furnished by Acurex-Aerotherm assembled under EPA contract (6). The costs cover retrofit installation only. The three techniques based on combustion modifications were Low NO_x Burners (LNB), Overfire Air Ports (OFA), and Low Excess Air Firing (LEA). Derating was also considered. Flue gas recirculation was not considered as this technique is not overly compatible with coal fired boilers. It was assumed that for all boilers, the use of LNB or OFA coupled with LEA would be sufficient to achieve the stipulated NO_x reduction level.

For cost purposes, it was assumed that LEA firing had no net cost since (1) this firing mode can be implemented relatively cheaply with low capital and operating costs, (2) a fuel savings and cost credit will result in most cases after LEA firing is implemented, and (3) many utility operators are already using LEA firing.

The general assumptions used by Acurex-Aerotherm included:

- Operation for 7000 hours/year at or near full load
- Unit five years old

TABLE 5-3. THERMAL DeNO$_x$ COST CALCULATIONS

• Initial NO$_x$ (ppm)	Input from Table 5-2
• Target NO$_x$ (ppm)	Input from Table 5-2
• Flue Gas Rate (kL /Hr)	Input from Boiler Manufacturers
• NO$_x$ Reduction Required	
- Percent	$= (1\text{-Target NO}_x/\text{Initial NO}_x) \times (100)$
- (Lb-ΔNO_2/Hr)	$= \left(\frac{\text{Initial NO}_x\text{-Target NO}_x}{10^6}\right) \times \left(\frac{46.0}{28.8}\right) \times (1000.) \times \left(\begin{matrix}\text{Flue}\\\text{Gas}\\\text{Rate}\end{matrix}\right)$
• Reagent Rate	
- NH_3/NO_I (Molar Ratio)	$= \Big\}$ From Thermal DeNO$_x$ Performance Prediction Procedure
- H_2/NH_3 (Molar Ratio)	
- NH_3 (kLb/Hr)	$= \left(\frac{NH_3}{NO_I}\right) \times \left(\frac{NO_I}{10^6}\right) \times \left(\frac{17.0}{28.8}\right) \times \left(\begin{matrix}\text{Flue}\\\text{Gas}\\\text{Rate}\end{matrix}\right)$
- H_2 (kLb/Hr)	$= \left(\begin{matrix}NH_3\\\text{Rate}\end{matrix}\ \frac{kLb}{Hr}\right) \times \left(\frac{H_2}{NH_3}\right) \times \left(\frac{2.0}{17.0}\right)$
• Carrier Rate (Air)	
- (SCFM Per Nozzle)	$= \left(\begin{matrix}\text{Carrier}\\\text{Rate}\end{matrix}\ \frac{kg}{Hr}\right) \times (0.484) = (9.7) \times (0.484) = 4.69$ For 100 Percent Load
- (SCFM Total)	= (SCFM Per Nozzle) x (No. Nozzles)
• Operating Cost	
- NH_3 (\$/Hr)	$= \left(\begin{matrix}NH_3\\\text{Rate}\end{matrix}\ \frac{kLb}{Hr}\right) \times \left(\frac{\$85}{kLb}\right)$
- Carrier (\$/Hr)	$= \left(\begin{matrix}\text{Carrier}\\\text{Rate}\end{matrix}\ SCFM\right) \times \left(\frac{1}{10{,}000}\right) \times \left(1100\ \frac{HP}{10k}\ SCFM\right) \times \left(0.746\ \frac{KW}{HP}\right) \times \left(\frac{\$0.03}{KW\cdot Hr}\right)$
- Total Operating Cost (\$/Hr)	= NH_3 + Carrier
• Fixed Cost*	
- NH_3 (k\$)	= Exxon Cost Estimating
- On-Sites	= Exxon Cost Estimating
- Carrier (k\$)	= Exxon Cost Estimating
- Total (k\$)	= NH_3 + On-Sites + Carrier

*NOTE: See assumptions Used in Cost Estimation for Further Details

THERMAL DeNO$_x$ COST CALCULATIONS (CONT'D)

- Equivalent Costs
  - Cost (\$/Lb ΔNO_2)
    - Operating Cost = Total Operating Cost (\$/Hr)/NO$_x$ Reduction Required (Lb ΔNO_2/Hr)
    - Yearly Fixed Cost = Total Fixed Cost (k\$) x $\frac{(1000)(0.2)}{(24)(365)(0.8)}$ x NO$_x$ Reduction (Lb ΔNO_2/Hr)
    - Total Cost = Operating Cost + Yearly Fixed Cost
  - Cost (\$/MW·Hr)
    - Operating Cost = Total Operating Cost (\$/Hr)/MW rating
    - Yearly Fixed Cost = Total Fixed Cost (k\$) x $\frac{(1000)(0.2)}{(24)(365)(0.8)}$ x MW rating
    - Total Cost = Operating Cost + Yearly Fixed Cost

- Remaining life of 25 years for accounting purposes

Indirect operating costs include depreciation expense, taxes, cost of capital and insurance. These costs are thus very similar to the capital costs used by Exxon and will be designated as such. Direct operating costs depend somewhat on the nature of the combustion modification technique but include any extra costs for fan power where used, increased maintenance, and a change for decreased unit efficiency where that occurs. These costs are quite similar to the operating costs used here and will be designated as such.

Acurex-Aerotherm established two different costs for the retrofit installation of OFA ports. These costs depended upon the boiler firing type and were lower for tangential than for wall fired units. For cost estimation purposes, it was assumed that the costs of installing overfire air ports in a Turbo furnace boiler was the same as for a wall fired unit. The LNB and OFA costs established by Acurex-Aerotherm in units of $/KW-Yr. were converted to mills/KW-Hr. in order to conform to the other data presented herein. The values in both units are presented in Table 5-4.

TABLE 5-4. COSTS FOR COMBUSTION MODIFICATIONS ESTABLISHED BY ACUREX-AEROTHERM

	Low NO_x Burners		Overfire Air Ports			
			Tangential		Turbo	
	$/KW-Yr	mills/KW-Hr	$/KW-Yr	mills/KW-Hr	$/KW-Yr	mills/KW-Hr
Operating	0.06	0.01	0.32	0.05	0.52	0.08
Capital	0.34	0.05	0.21	0.03	0.16	0.02
Total	0.40	0.06	0.53	0.08	0.68	0.10

The derating of a boiler will also result in reduced emissions of NO_x. As will be apparent, derating is very expensive and consequently would be used only as a last resort when other combustion related procedures cannot achieve target NO_x levels. Derating will not be considered for use in association with Thermal $DeNO_x$, although it will be utilized for comparative purposes in a subsequent section.

The basic costs for derating were also furnished by Acurex-Aerotherm (6). Acurex-Aerotherm considered staged combustion in which burners would be removed from service, thereby derating the boiler by an amount equal to 20% of capicity. The operating cost thus is largely the purchase of make up power which Acurex-Aerotherm assumed was purchased at 2.5¢/KW-Hr. Acurex-Aerotherm believes that this value approximates the cost of generating electricity. Transmission costs were assumed to be minimal at 0.1¢/KW-Hr yielding a total cost for purchased power of 2.6¢/KW/Hr. Other factors included in the operating cost are a fuel credit for fuel not used and a very minor loss in efficiency. Aerotherm estimated the operating cost to be $24.78 KW/Yr.

The capital cost figure determined by Acurex-Aerotherm reflects the lost capacity. The boiler has been financed on the basis of full rated output but because the boiler has been derated either, (a) a longer period will be required to recover this financial quantity or (b) an increased rate of recovery over the same period must be used. The capital charge thus represents a lost capital charge.

The Acurex-Aerotherm values were converted to the bases used here and the results are presented in Table 5-5.

TABLE 5-5. COSTS FOR BOILER DERATING

	Derate by 20% - Burners out of Service	
	$/KW-Yr	mills/KW-Hr
Operating	24.78	3.54
Capital	5.34	0.76
Total	30.12	4.30

It was assumed that either low NO_x burners or the use of overfire air, perhaps in combination with LEA firing as required, were sufficient to reach the initial NO_x level designated. The combustion modification which was used for each boiler type is shown in Table 5-6.

TABLE 5-6. COMBUSTION MODIFICATIONS USED TO REDUCE INITIAL NO_x LEVELS

Boiler		
Manufacturer	Size	Combustion Modification
B & W	130	Low NO_x Burners
	333	Low NO_x Burners
	400	Low NO_x Burners
CE	350	Overfire Air
	800	Overfire Air
F-W	330	Low NO_x Burners
	700	Low NO_x Burners
RS	700	Overfire Air

SECTION 6

RESULTS AND DISCUSSION

The feasibility and costs for using the Exxon Thermal DeNO$_x$ Process on eight representative coal fired utility boilers was established for several target NO$_x$ levels. These target NO$_x$ levels included:

a. Reduction by trimming to the proposed New Source Performance Standards (NSPS) of 0.6 lb NO$_x$/MBtu (450 ppm NO$_x$) for bituminous and lignite fired boilers and 0.5 lb NO$_x$/MBtu (375 ppm NO$_x$) for boilers fired with subbituminous coal.

b. Deep reduction in NO$_x$ levels to 0.4 lb NO$_x$/MBtu (300 ppm NO$_x$) for boilers fired with bituminous coal and lignite and to 0.3 lb NO$_x$/MBtu (225 ppm) for subbituminous fired boilers.

In summary, this analysis projected that the proposed NSPS could be met by all boilers studied using the Thermal DeNO$_x$ Process alone and that all boilers, except the cyclone boiler fired with lignite, could meet the deep reduction target using Thermal DeNO$_x$ coupled with combustion modifications. The performance of the Thermal DeNO$_x$ process was considered to be essentially equivalent for all boilers evaluated even though significant differences existed in flue gas temperature profiles and flow path configurations among boilers. These differences resulted in the selection of significantly different injection grid locations among the boilers of different manufacturers.

It was projected that the ammonia injection grid location would not be affected significantly by assuming a 50°C larger temperatue range in the injection plane than that used for baseline calculations. However, a temperature range increase of this size would reduce DeNO$_x$ performance by 5 to 10 percentage points (e.g. from 50% to 40-50%). It was also found that total NO$_x$ removal costs increased when hydrogen (rather than dual grids) was used with only one grid to realize effective DeNO$_x$ at lower than full boiler loads.

Other specific projections and conclusions were as follows:

- All units could reach the proposed NO$_x$ NSPS using Thermal DeNO$_x$ alone. Some units could also reach this level using combustion modifications alone.

- All units except one could meet the deep NO_x reduction target when Thermal $DeNO_x$ was used in combination with combustion modifications. The one exception was the cyclone boiler fired with lignite.

- Projected costs to reach the proposed NSPS from an uncontrolled base level ranged from 0.25 mills/KW-Hr for the 250 MW CE boiler to a high of 1.17 mills/KW-Hr for the lignite fired cyclone boiler. The average cost for all boilers considered was 0.57 mills/KW-Hr, or 0.49 mills/KW-Hr not including the cyclone boiler.

- Four of the eight boilers could reach the deep reduction target using Thermal $DeNO_x$ alone. Costs ranged from 0.38 mills/KW-Hr to 0.83 mills/KW-Hr for these boilers.

- Projected costs to reach the deep reduction target using Thermal $DeNO_x$ with combustion modifications ranged from 0.38 mills/KW-Hr to 0.51 mills/KW-Hr with the average being 0.44 mills/KW-Hr for the seven boilers reaching the target level.

- NO_x reductions ranging from 62% to 76% and averaging 70% relative to an uncontrolled base case could be achieved using Thermal $DeNO_x$ at a maximum practical level in combination with combustion modifications. NO_x levels in the 0.20 to 0.23 lb. NO_x/MBtu range could be realized for most of the boilers. Costs ranged from 0.55 to 1.14 mills/KW-Hr and averaged 0.68 mills/KW-Hr for all boilers studied. With the lignite boiler excluded the range was 0.55 to 0.67 mills/KW-Hr and the average was 0.61 mills/KW-Hr.

- The costs for onsites and the carrier were found to be proportional to boiler size.

- The total ammonia reagent costs for all cases normalized for the mass of NO_x removed expressed as NO_2 (ΔNO_x) were nearly equal for all eight units studied at 0.09 \$/lb.ΔNO_x. This parameter was considered to be a good overall judgement criterion of the chemical efficiency and economic efficacy of the Thermal $DeNO_x$ process.

- The Exxon Thermal $DeNO_x$ Process was considered to be equally amenable to all units studied.

- The costs for reaching NO_x levels in the 0.3 to 0.4 lb./MBtu range were compared for Thermal $DeNO_x$ and combustion modifications. The costs of most conventional combustion modifications and combinations thereof were lower than that of Thermal $DeNO_x$. Extreme NO_x reduction methods such as derating or staged combustion that incurred derating would be more expensive. Derating would not generally be used as a NO_x reduction technique.

The practical effectiveness of Exxon Thermal $DeNO_x$ process can be determined from several evaluations which were performed during this study. These are:

1. The percent reduction in NO_x levels predicted by the Thermal $DeNO_x$ Performance Prediction Technique.

2. The feasibility and costs for reducing NO_x emissions to the specified target NO_x levels, with and without combustion modifications.

3. The maximum reduction in NO_x levels achievable and the costs required to accomplish this reduction.

4. The total ammonia operating costs normalized to the cost per pound of NO_x removed.

5. Comparison of costs for Thermal $DeNO_x$ with costs for combustion modifications to reach 0.3 to 0.4 lb. NO_x/MBtu.

6. The effect of unanticipated temperature gradients in the plane of ammonia injection on Thermal $DeNO_x$ performance and grid placement.

7. Load following using hydrogen along with ammonia rather than using multiple grids.

The results obtained in each of these areas are presented in the following subsections.

PREDICTED PERCENT NO_x REDUCTION LEVELS

The Thermal $DeNO_x$ Performance Prediction Procedure has been discussed above. In summary, this calculational procedure utilizes boiler dimensional information, flue gas mass flow, temperature and critical residence times to arrive at a predicted value for maximum percentage NO_x reduction as a function of ammonia injector grid location.

The percentage NO_x reduction which could be anticipated for each of the eight boilers as predicted using the Exxon procedure with NH_3/NO_x molar ratios of 1.0 and 1.5 has been calculated. The results have been determined for 100% load and in most cases one or more lower loads. The results obtained are presented in Table 6-1.

The percentage NO_x reductions calculated for the coal fired utility boilers studied operating at full load averaged 44.6% at the molar ratio of 1.0. The range for all boilers considered was 41-47%. At a molar ratio of 1.5, the average $DeNO_x$ performance increased to about 57.5%. In this case, the range extended from 54 to 63%. These results may be considered to be typical of $DeNO_x$ performance.

TABLE 6-1. PREDICTED THERMAL DeNO$_x$ PERFORMANCE ACHIEVABLE AT FULL, 75% AND 50% LOAD

Boiler Manufacturer	MW	Coal Type	Percent NO$_x$ Reduction at Boiler Load and NH$_3$/NOI Ratio Indicated					
			100%		75%		50%	
			1.5	1.0	1.5	1.0	1.5	1.0
B&W	130	Subbituminous	52	42	52	42	63	50
B&W	333	Bituminous	63	48	57	44	57	44
B&W	400	Lignite	58	43	58	43	--	--
CE	350	Bituminous	58	45	52	40	48*	37*
CE	800	Subbituminous	57	45	52	40	50*	38*
F-W	330	Bituminous	54	41	--	--	--	--
F-W	670	Subbituminous	60	47	--	--	--	--
RS	350	Bituminous	58	46	--	--	54*	45*

*60% Load

It should be noted that the temperature profile and flow path configuration for the Riley Stoker boiler differed considerably from the other boilers considered and from the temperature patterns used in formulating the Thermal DeNO$_x$ Performance Prediction Procedure. As a consequence, the values for the performance of the Thermal DeNO$_x$ process on this unit and the values of costs which derive from these should be considered to be subject to a greater degree of uncertainty than the other boilers studied.

Application of the Performance Prediction Procedure revealed that there are definite differences from manufacturer to manufacturer in the flue gas temperature profiles and flow path configurations. For example, the injection grids would be located closest to the furnace exit for the CE units and furthest downstream for the F-W units. As was noted above and will be stated later, the performance (and costs) were effected only minimally by these configurational differences

FEASIBILITY AND COSTS

The feasibility of using the Exxon Thermal DeNO$_x$ process and the resulting costs required to reach (a) a final NO$_x$ level where NO$_x$ emissions would be "trimmed" and (b) where a significant reduction would be made in NO$_x$ emissions have been evaluated. As noted earlier, the trim case called for reducing NO_x emissions to 450 ppm NO_x for bituminous coal and lignite firing and 375 ppm NO_x for subbituminous. These are the proposed NSPS levels. The other group of NO_x reductions required would be significant, to 300 ppm NO_x for bituminous and lignite and 225 ppm NO_x for subbituminous. In order to fully evaluate the capabilities for the Thermal $DeNO_x$ process to meet the target levels and to establish a range of costs where practical two initial NO_x levels were considered: one in which NO_x emissions were uncontrolled and the other in which combustion modifications were used. Thus, four cases were formulated:

Case 1: Combustion modifications (CM) cannot be used and initial NO_x level is baseline NO_x level. Trim case.

Case 2: CM can be used to reduce initial NO_x levels. Trim case.

Case 3: CM cannot be used. Deep NO_x reduction case.

Case 4: CM can be used. Deep NO_x reduction case.

By the use of this approach, a range of costs has been established for those cases where appropriate NO_x reductions could be achieved. The nature of the combustion modification utilized for each boiler was noted earlier. A summary of the results obtained is presented in Table 6-2. Additional detail summarizing the costs of ammonia, carrier and the onsite cost are presented in Appendix 1.

The costs presented here are for those representative boilers selected for study. It should be recognized that each potential candidate boiler for the Thermal $DeNO_x$ process must be studied on an individual basis.

Table 6-2 shows that at full boiler load and without combustion modifications, the NO_x emissions from each boiler can be reduced to the NSPS NO_x target using Thermal $DeNO_x$. The costs for the application of the Exxon Thermal $DeNO_x$ process for the Case 1 trim cases ranged from a low of 0.25 mill/KW-Hr. for the 250 MW CE boiler to a high of 1.17 mills/KW-Hr. for the lignite fired cyclone boiler. The cost for this boiler was more than double that for almost all the other boilers. Excluding the lignite boiler, the average cost was about 0.49 mills/KW-Hr.; with the lignite boiler included, the average cost was just over 0.57 mills/KW-Hr. The high cost for the lignite-fired boiler can be attributed to the very high initial NO_x level assumed for this boiler. The costs of reducing NO_x emissions from an uncontrolled baseline level to the proposed NSPS depends upon a number of considerations including initial NO_x level. This will significantly influence the cost for the ammonia used. Examination of the data in Appendix 1 reveals that unit size can have some influence on the on-site cost and that the carrier cost is generally proportional to the flue gas flow rate. The inherently low NO_x emissions from the CE tangentially fired boilers are responsible for the low Thermal $DeNO_x$ costs determined for these units.

With combustion modifications, the NSPS NO_x targets can also be reached. In fact, for five of the eight boilers, this target NO_x level can be achieved

TABLE 6-2. COSTS FOR REDUCING NO_x EMISSIONS OF COAL FIRED UTILITY BOILERS USING THERMAL $DeNO_x$†

				Trim Cases					Deep Reduction Cases					
				Case 1 W/O Comb. Mod.		Case 2 With Comb. Mod.			Case 3 W/O Comb. Mod.		Case 4 With Comb. Mod.			
Manuf.	Size, MW	Firing Type	Coal Type	Initial NO_x, ppm	Cost Mills/KW-Hr	Initial NO_x, ppm	Cost Mills/KW-Hr	Final NO_x, ppm	Initial NO_x, ppm	Cost Mills/KW-Hr	Initial NO_x, ppm	Cost Mills/KW-Hr	Final NO_x, ppm	Percent Reduction From Uncontrolled Case
B&W	130	FW	Subbit.	500	0.49	300	0.06*	375	500	**	300	0.47	225	55
	333	HO	Bit.	700	0.45	420	0.06*	450	700	0.63	420	0.38	300	57
	400	Cyclone	Lig.	1000	1.17	900	0.99	450	1000	**	900	**	300	--
CE	350	Tan	Bit	500	0.25	450	0.08*	450	500	0.38	450	0.42	300	40
	800	Tan	Subbit.	530	0.34	375	0.08*	375	530	0.62	375	0.42	225	58
F-W	330	FW	Bit	850	0.71	510	0.33	450	850	**	510	0.50	300	65
	670	HO	Subbit.	700	0.63	420	0.31	375	700	**	420	0.51	225	61
RS	350	Turbo	Bit	700	0.54	420	0.10*	450	700	0.83	420	0.45	300	57

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*Thermal $DeNO_x$ not required. Final NO_x level attainable using combustion modifications.

**Target NO_x level cannot be reached.

† Thermal $DeNO_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

using combustion modifications alone. Because the cost of simple combustion modifications is far smaller than that of Thermal DeNO$_x$, combustion modifications would represent the preferred, cost effective approach for these boilers. In fact, only three boilers required use of the Thermal DeNO$_x$ process, the 400 MW B&W boiler firing lignite and the two F-W boilers. As was noted previously, the lignite boiler has a very high initial NO$_x$ level, and in all cases studied meeting NO$_x$ target levels would be either expensive or impossible. In this case, the use of combustion modifications lowers the cost of Thermal DeNO$_x$ by about 16%. Still the cost of Thermal DeNO$_x$ for this unit using Case 2 NO$_x$ levels is about three times as great as for any of the other units studied. The combination of boiler size and coal type selected for the F-W Boilers (resulting in the NO$_x$ levels specified) is probably responsible for the requirement to use Thermal DeNO$_x$ in these cases. Here, however, the use of combustion modifications serves to reduce the cost of Thermal DeNO$_x$ by 55% for the 330 MW boiler and by 52% for the 670 MW unit.

The reduction of NO$_x$ in Case 3 is the most difficult because of (a) the high initial NO$_x$ levels and (b) the deep reduction target. In fact, in this case only half of the boilers studied were able to achieve the target NO$_x$ levels. The Thermal DeNO$_x$ costs for those boilers which met the target ranged from 0.38 to 0.83 mills/KW-Hr. Because so few boilers were able to meet this target, additional cases were established for the maximum reduction in NO$_x$ emissions which could be achieved. These cases are discussed in the following subsection.

Case 4 considers a deep reduction in NO$_x$ emissions achievable by Thermal DeNO$_x$ in conjunction with combustion modifications. In this case, all boilers except that firing lignite met the target NO$_x$ level. It is interesting to note that the cost spread in this case was rather narrow, ranging from 0.38 to 0.51 mills/KW-Hr. with the average being 0.44 mills/KW-Hr. This average cost is lower than the average cost determined for Case 1 where the NO$_x$ target was not as low and combustion modifications were not utilized to lower the initial NO$_x$ level. The overall NOx reductions achieved by the combination of Thermal DeNO$_x$ and combustion modifications from an uncontrolled base case ranged from 40% to 65% with the average reduction approximating 56%. Thus, the combination of Thermal DeNO$_x$ and combustion modification was found capable of meeting deep reductions in NO$_x$ emissions on existing boilers with a wide range of sizes, from all manufacturers, utilizing different firing types and, with the exception of lignite fired in a cyclone boiler, all fuels.

MAXIMUM REDUCTION OF NO$_x$ LEVELS

In addition to the four cases noted previously, two additional cases were studied in which NO$_x$ was reduced to the lowest level attainable by Thermal DeNO$_x$ as specified by the Performance Prediction Procedure with the injector grid at the location selected for full load (i.e., the grid location was the same as in the cases noted previously). Thus two additional cases are defined:

Case 5: Maximum DeNO$_x$ without combustion modifications.

Case 6: Maximum DeNO$_x$ with combustion modifications.

Without CM, Case 5, the percent NO$_x$ reduction realized ranged from 50 to 59%. Costs ranged from 0.57 mills/KW-Hr. for the small CE boiler to 1.23 mills/KW-Hr. for the lignite boiler; most cases were in the 0.57 to 0.87 mills/KW-Hr. range, the high value for lignite again being attributable to the high initial NO$_x$ level. The results for all boilers are presented in Table 6-3.

Combustion modifications, plus Thermal DeNO$_x$, Case 6, combined to reduce NO$_x$ levels an average of 70% from the uncontrolled base case. The ranges extended from 62 to 76% reduction in NO$_x$. Final NO$_x$ levels in the 150 to 175 ppm range were realized for five of the eight boilers. Again the lignite boiler was a significant NO$_x$ producer, possessing final NO$_x$ emission level greater than twice that of the five boilers noted above.

In terms of cost, the lignite boiler had a total cost of 1.14 mills/KW-Hr. The cost for all the other boilers fell in the rather narrow range of 0.55 to 0.67 mills/KW-Hr., again about half the cost of the lignite boiler. Excluding the lignite boiler, the average cost was 0.61 mills/KW-Hr. Including the lignite boiler, the average cost increased to 0.68 mills/KW-Hr.

NORMALIZED AMMONIA AND OTHER OPERATING COSTS

The total ammonia reagent costs expressed on the basis of the quantity of NO$_x$ removed is an excellent measure of the efficiency of the Thermal DeNO$_x$ Process for combustion equipment. Specifically, for coal fired utility boilers, this study found that when ammonia-related costs were normalized with respect to the pounds of NO$_x$ removed, NO$_x$:

- Total reagent costs were nearly equal for all units in all cases at 0.09 \$/lb. NO$_x$ removed.
- Operating costs for all units in all cases approximated 0.08 \$/lb. ΔNO_x.
- Capital costs for all units in all cases were about 0.01 \$/lb. ΔNO_x.

These costs are presented in Appendix 1 for each case considered for each boiler. The range of ammonia operating costs for each case considered for each boiler is shown in Figure 6-1. The small differences in Thermal DeNO$_x$ efficiency which made some units slightly lower than the average values noted above were not considered to be significant.

Of the ammonia cost, approximately 10% represents capital investment for the storage facilities, and the balance is the operating cost for the ammonia supply. At lower ammonia rates (such as less than approximately

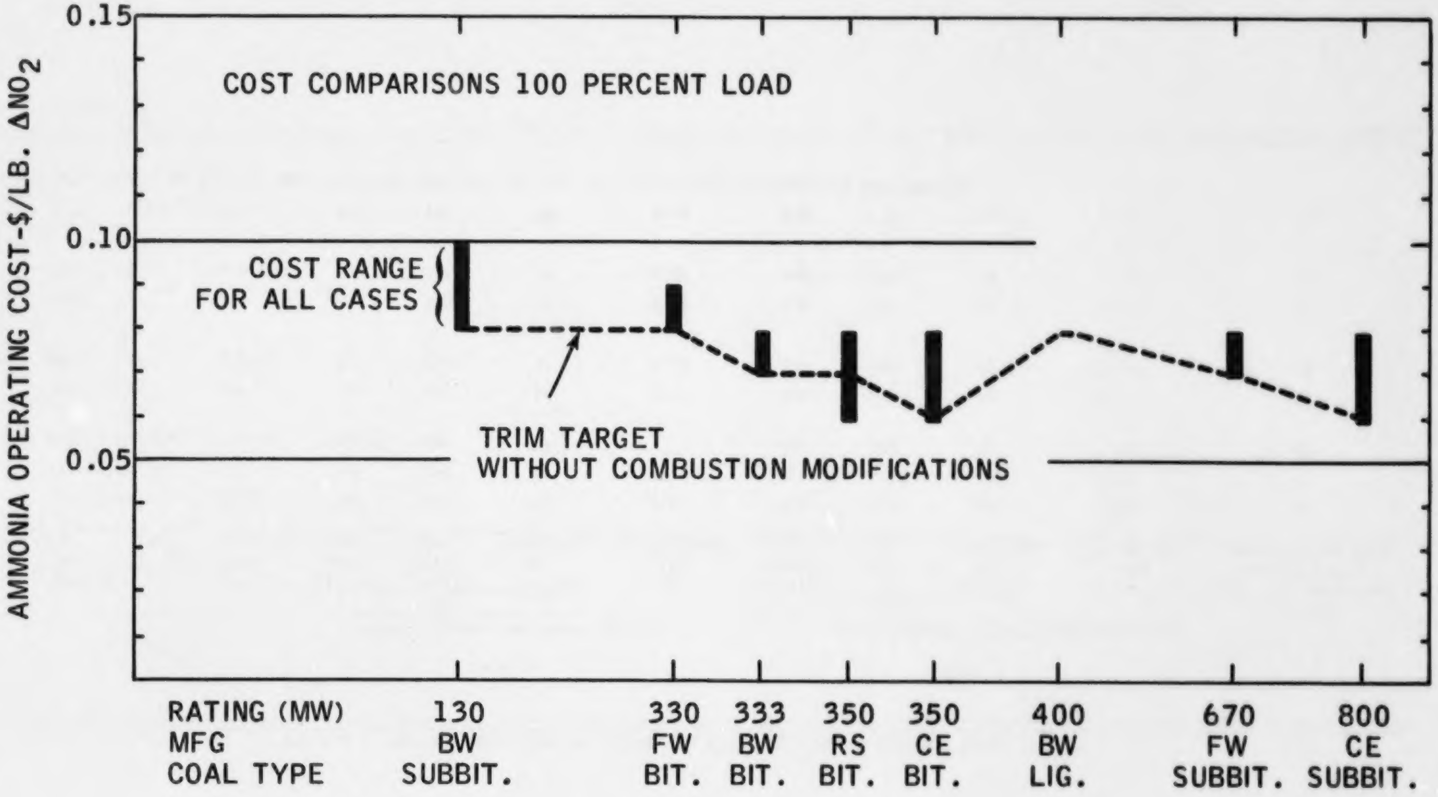

Figure 6-1 Ammonia operating costs for boilers studied.

TABLE 6-3. MAXIMUM PRACTICAL NO_x REDUCTION ACHIEVABLE USING THERMAL $DeNO_x$†

				Case 5				Case 6				
				Without Combustion Modifications				With Combustion Modifications				
				NO_x				NO_x				
	Boiler											
Manuf.	Size, MW	Firing Type	Coal Type	Initial Level, ppm	Final Level, ppm	Percent NO_x Reduction	Total Cost Mills/KW-Hr	Initial Level, ppm	Final Level, ppm	Percent NO_x Reduction	Total Cost, Mills/KW-Hr	Percent Total NO_x Reduction Possible From Uncontrolled Case
B&W	130	FW	Subbit.	500	250	50	0.71	300	150	50	0.60	70
	333	HO	Bit.	700	290	59	0.70	420	175	58	0.55	75
	400	Cyclone	Lignite	1000	430	57	1.23	900	385	57	1.14	62
CE	350	Tan	Bit.	500	210	58	0.57	450	190	58	0.61	62
	800	Tan	Subbit.	530	230	57	0.62	375	160	57	0.59	70
F-W	330	FW	Bit.	850	390	54	0.82	510	230	55	0.62	73
	670	HO	Subbit.	700	290	59	0.87	420	170	59	0.65	76
RS	350	Turbo	Bit.	700	295	58	0.84	420	175	58	0.67	75

† Thermal $DeNO_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

1000 lb/Hr) the facilities cost is a greater fraction of the total as expressed on a KW-Hr. basis.

Other categories of cost items (carrier cost and on-site costs) determined were considered to be related to boiler size rather than to the efficiency of NO_x removal as was the reagent cost (see Figure 6-2). The carrier cost, for example, was found to be a function of flue gas flow rate. The latter value was found to be roughly proportional to unit size. Normalized carrier cost was found to be nearly constant for all units at 0.14 mills/KW-Hr. Approximately half of this cost was capital investment and half was operating cost.

The on-sites costs which includes the cost of the ammonia injection grid was found to be a function of unit size. Normalized, the on-site capital investment was found to be in the range of 0.04 to 0.05 mills/KW-Hr for all units, except for the smallest B&W boiler. The normalized cost for this boiler was approximately double that of the average.

COST COMPARISON OF THERMAL $DeNO_x$ WITH COMBUSTION MODIFICATION TECHNIQUES

A reliable comparison of the costs of Thermal $DeNO_x$ versus extreme combustion modifications required to reduce NO_x emissions to the 0.3 to 0.4 lb/MBtu range would be very valuable. Unfortunately, as of this writing, no publically disseminated information is available from the boiler manufacturers concerning the cost of combustion modifications to reach NO_x levels within this range. In general, combinations of several combustion modification techniques will be required to reach the NO_x levels noted above. In section 5, the costs for several combustion modification techniques were developed. These costs can be applied to available NO_x reduction information obtained on utility boilers.

One example presented below describes the use of low NO_x burners plus the extreme combustion modification technique of derating to reach the 0.4 lb/MBtu NO_x range. The other describes the use of two conventional combustion modification techniques, low NO_x burners combined with overfire air, to reach the same level.

The first example considered here is that of the use of low NO_x burners plus derating. Actual performance data has been obtained under EPA contract by Exxon Research on a 270 MW B&W boiler with horizontally opposed firing of eastern bituminous coal (4). Data were obtained (a) before and after the installation of low NO_x burners (LNB) and (b) using LNB in combination with derating of the boiler by about 20% by shutting off one row of coal pulverizers (Run 37 in reference 4). Table 6-4 presents the data obtained.

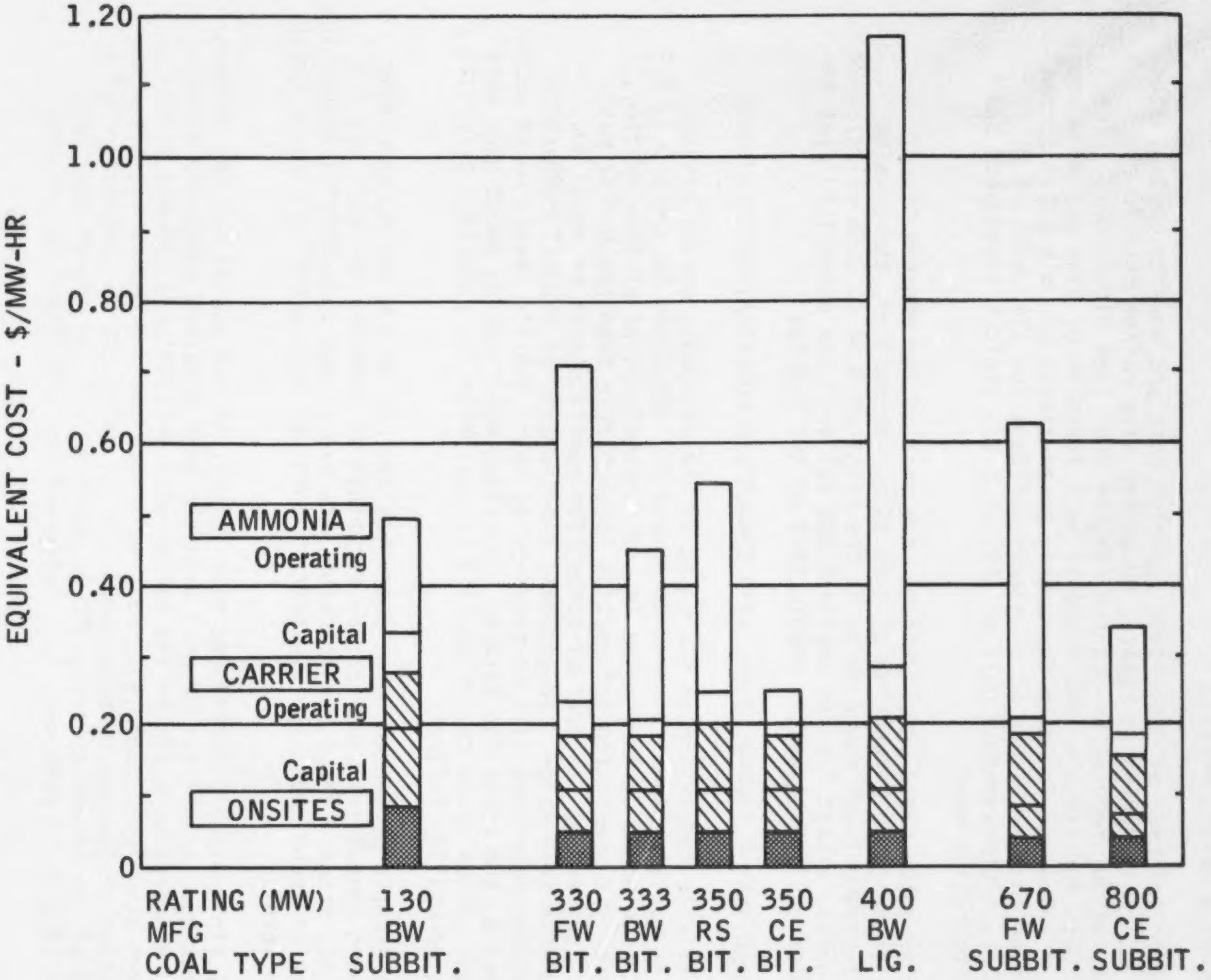

Figure 6-2 Cost comparisons for trim target without combustion modifications - 100 percent load.

TABLE 6-4. NO_x LEVELS ON 270 MW B&W HO BOILER

	NO_x Level		
	ppm	lb/MBtu	Load, MW
Uncontrolled	600	0.8	270
Low NO_x burners	375	0.5	270
Low NO_x burners + Derate	300	0.4	208 (23% derate)

In this case derating the boiler by 23% reduced NO_x levels to the 0.4 lb/MBtu (300 ppm) NO_x. This example is very similar to that of the B&W HO 333 MW boiler firing bituminous coal considered in this study. The initial NO_x level was 700 ppm for this boiler and in Case 4, the final level was 300 ppm. The cost calculated for Thermal $DeNO_x$ plus combustion modifications (low NO_x burners) was 0.38 mills/KW-Hr. For low NO_x burners plus derating the cost would be: 4.30 + 0.06 mills/KW-Hr = 4.36 mills/KW-Hr. Thermal $DeNO_x$ is obviously far cheaper than the case presented here because of the very high cost of derating. If the staging of burners to achieve target NO_x levels results in less than full load (thus effectively derating the boiler), the costs for staging can be expected to be similar to the derating case illustrated here.

Another example is that described by Vatsky (7) of a Foster-Wheeler 265 MW bituminous-fired utility boiler retrofitted with overfire air ports and F-W low NO_x burners. Even with conventional, high turbulence burners, this boiler possessed an initial NO_x level which was within the 600-650 ppm NO_x (0.8 lb NO_x/MBtu) range. This low initial level was ascribed to the large, conservatively designed fireboxes which this unit possessed. Under normal operating procedure for this boiler, NO_x levels were in the 300-350 ppm (0.4 lb NO_x/MBtu) range using the low NO_x burners and with the overfire air ports open no more than 20%. (Still lower emissions could be attained by this boiler - down to 200-225 ppm NO_x - with overfire air ports fully open, but unburned carbon emissions and slag deposits increased.) The applicable NO_x levels are presented in Table 6-5.

TABLE 6-5. NO_x LEVELS ON 265 MW F-W HO BOILER

	NO_x Level		%
	ppm	lb/MBtu	Reduction
Uncontrolled	600	0.83	--
Overfire Air Only	425	0.56	32
Low NO_x Burners Only	375	0.50	40
OFA + LNB	300	0.40	50

The costs for accomplishing this reduction in NO_x using previously stated values are:

Low NO_x Burners	0.06 mills/KW-Hr
Overfire Air Ports	0.10 mills/KW-Hr
Total	0.16 mills/KW-Hr

The value of 0.16 mills/KW-Hr is clearly lower than any of the Thermal $DeNO_x$ costs required to reach the 0.4 lb/MBtu range. It should be noted, however, that neither of the combustion modification techniques used here could be regarded as extreme, but were rather quite conventional.

In general, it can be stated that the costs required to achieve low NO_x emission levels will be dependent upon the boiler and the modifications which can be applied on a practical basis. The examples presented here illustrate a range of costs to reach the stated low levels of NO_x, some greater than and some less than Thermal $DeNO_x$. Where combinations of simple combustion modifications can be applied successfully to reach the target levels of 0.3 to 0.4 lb/MBtu, combustion modifications will probably be the preferred techniques. Where boiler inflexibility or other conditions prevent the use of most combustion modifications and derating or staging which results in derating the boiler are the only combustion-related approaches left to meet specified emission levels, Thermal $DeNO_x$ will be the preferred technique. Clearly, more refined costs for combinations of combustion modifications, including case histories, are required before authoritative comparisons can be undertaken.

TEMPERATURE NONUNIFORMITY SENSITIVITY STUDY

The effectiveness of the Exxon Thermal $DeNO_x$ Process is critically dependent on temperature. Thermal $DeNO_x$ performance is a function of the cross sectional temperature throughout the reaction zone. Because of this significant dependence, the level of NO_x reduction attainable will depend upon placing the ammonia injection grid in the proper location. One major variable which is encountered in operating boilers is the nonuniformity in temperature of the flue gas. A series of values to account for this ΔT are incorporated into the Performance Prediction Procedure used. This Procedure assumes that a range of temperatures is present in the plane of the injection grid. This temperature range is assumed to be gradually smoothed out downstream of the grid. If the flue gas temperature range is significantly different from that used in the Performance Prediction Procedure, it is possible that the grid or grids could be improperly located thereby resulting in less than predicted $DeNO_x$ performance. As a consequence a sensitivity analysis was undertaken for this study using one boiler in which different temperature ranges, that is different values of ΔT, were used in the performance prediction technique. This sensitivity analysis is described below.

Initial studies of the suitability of a unit to Thermal $DeNO_x$ application require that an estimate of the ΔT be made for each proposed injector location based upon experience with similar units. The values of ΔT used in calculating performance for this EPA study were based upon data taken in a Japanese 160 MW utility boiler. It must, however, be realized that the cross sectional temperature distributions may be quite different even among units of similar design. Burner firing patterns, air leakage, flow obstructions, etc. are factors which can affect the temperature pattern.

Application of Exxon Thermal $DeNO_x$ Performance Prediction Procedure revealed that the locations of the injector grids would not be influenced by a temperature range up to 50°C larger than that used in the Performance Prediction Procedure for the other cases presented. However, a temperature range of this magnitude could result in $DeNO_x$ performance much differed from the predicted values by 5 to 10 percentage points, for example, performance could be reduced from 50% $DeNO_x$ to 40-45% $DeNO_x$.

USE OF HYDROGEN FOR LOAD FOLLOWING

There are several approaches for using Thermal $DeNO_x$ to achieve suitable NO_x reductions with different boiler loads. One method involves the use of multiple grids each designed to cover one or more boiler loads. Only NH_3 plus carrier are used. This has been the approach studied in the other sections of this report. In this section, the results are presented for a second approach studied for maintaining NO_x reductions during reductions in boiler load. A single injector rather than two was installed, and hydrogen was injected along with ammonia and carrier during periods of boiler load reduction to maintain the NO_x target. As was noted earlier in this report, the use of hydrogen in the Thermal $DeNO_x$ Process serves to shift the critical temperature window to lower temperature values, thereby enabling the process to effectively accomodate reduced load. The use of hydrogen, however, does not widen the temperature window; hydrogen merely lowers it. The necessity for using hydrogen has been obviated to a large extent because of the demonstration conducted at Exxon Research which showed that ammonia may be injected into boiler tube banks and into cavities with essentially equal success. For most ammonia-only applications more than one grid will be required in order to have $DeNO_x$ performance at different loads. In considering the use of hydrogen, it was assumed that only one grid would be used and the temperature lowering ability of hydrogen would permit $DeNO_x$ performance at lower loads and thus lower temperatures. As a consequence, in these hydrogen examples, reduced on-sites costs would be "traded off" for increased reagent costs.

The hydrogen examples presented here are only one of several grid/hydrogen combinations possible. Possible combinations include:

1 grid - no hydrogen
1 grid - with hydrogen
2 grids - no hydrogen
2 grids - with hydrogen

It is the second combination which has been studied here and contrasted with the two grid - no hydrogen combination which forms the basis for the balance of this investigation.

The effect of hydrogen addition was calculated for the 333 MW Babcock and Wilcox unit at 75 and 50 percent loads. The use of hydrogen permits possible savings in two areas: (1) the installation of only a single grid and (2) reduced carrier rates since cooling of an idling second grid is not required. The location of this single grid is based on the frequency of load changes and normal operating conditions. We have assumed that maximum target reductions must be maintained at all load variations, and costs for each load are based on continuous operation at that load. Grid placement was critical in that one location was required to cover the three loads assumed.

Six different examples were studied in undertaking this analysis of the effect of hydrogen addition on extending the useful range of a single grid system at lower boiler loads (see Table 6-6). The first three examples involve the use of two grids. The first example is identical to the general Case 3 (deep NO_x reductions and no combustion modifications) and considers initial and final NO_x levels of 700 ppm and 300 ppm, respectively, at full loads. The second example considered here assumes 75% load and initial and final NO_x levels of 630 ppm and 300 ppm, respectively. In the third example considered here, the boiler was assumed to be operating at 50% load with an initial NO_x level of 560 ppm and a final NO_x level of 252 ppm. The latter

TABLE 6-6. EXAMPLES CONTRASTING SINGLE GRID-HYDROGEN AND DUAL GRID FOR LOAD FOLLOWING

Example	Number of Grids	Hydrogen Used	Boiler Load, %	NO_x Levels, ppm Initial	NO_x Levels, ppm Final
A	2	No	100	700	300
B	2	No	75	630	300
C	2	No	50	560	252
D	1	No	100	700	300
E	1	Yes	75	630	300
F	1	Yes	50	560	252

NO_x level represented the lowest NO_x level which could be realized. In the fourth, fifth and sixth examples, only one grid was assumed to be used. The initial and final NO_x levels as well as boiler loads for these examples are the same for the first, second and third examples considered here, respectively. Hydrogen is added as required to meet the $DeNO_x$ targets in the fifth and sixth hydrogen examples.

The assumptions which were used in applying the Thermal $DeNO_x$ Performance Prediction Procedure are listed below:

1. There is one injection location which must meet all the reductions required of a dual injector system.
2. The grid must be located where the performance at each of the loads without hydrogen is greater than zero.
3. The carrier is air.
4. The carrier temperature is 80°C at the feed pipe entry point into the flue gas duct.
5. The effect that a temperature distribution would have on the hydrogen reaction was neglected.

The assumptions used in cost estimating for the hydrogen costs are listed below:

1. Fixed costs are total erected cost, 2nd Quarter 1977, U.S. Gulf Coast, no escalation and no contingency included.
2. Ammonia fixed costs include NH_3 storage vessel, vaporizer, and piping. Hydrogen is supplied on truck mounted pressurized cylinders and is fed into the same piping system used to handle the ammonia.
3. Carrier fixed costs include air compressor and piping.
4. On-site fixed costs include one injector grid, plus instrumentation and controls for ammonia and hydrogen.
5. Operating costs are for continuous operation at 100, 75 and 50% loads.
6. The NH_3/NOI ratio is assumed to be constant at 1.5. This ratio was determined from plots of data obtained by Exxon Research.
7. Calculated NH_3 and H_2 consumptions are based on nominal initial NO_x levels and flue gas flow rates. No adjustments have been made for variations in excess air levels and flue gas moisture content.

8. Reagent operating costs for NH_3 and H_2 are based on $85 and $1400 per 1000 lb., respectively.

9. Carrier rate, for cost calculations, was 6.45 kg/hr/nozzle at all loads. Excess carrier was assumed to be vented when not needed.

10. Carrier operating costs are calculated in the same manner as the non H_2 injection studies.

11. Annual amortization is taken as 20% of investment. This figure represents finance costs and maintenance. Annual service factor is 80% of full load.

The costs projected are plotted in Figure 6-3 as a function of pounds of NO_x removed for the three loads. This figure shows that extensive operation at reduced loads can best be handled with a dual injector system. However, if minor variations in load are foreseen for only short durations there may be economic incentives for the use of hydrogen with a single grid rather than for installing a second ammonia grid.

For full load, this study projected that the overall cost for a single grid system operating with NH_3 as the only reagent (i.e. no hydrogen) would be almost identical to that of a dual grid system. Clearly, the grid and carrier cost for the single grid system would be lower than for the dual grid system. However, because the grid position was selected to provide NO_x reduction coverage at all loads considered, it was not optimal for any one load. The single grid location was a compromise and, for full load, the ammonia operating costs were somewhat higher for the single injection system that for the dual grid system (see Figure 6-3). Thus, the higher capital costs of the two grid system were balanced by the higher operating costs of the single grid system. If the operating time at each load had been established, it should be possible to identify a single grid position which would result in lower operating costs.

For 75 and 50 percent load, hydrogen would be used in order to maintain the specified $DeNO_x$ coverage. For these reduced load examples, it was projected that the total cost of single grid operation in which hydrogen was used were higher than the dual grid examples, but the substantially higher operating costs for the single grid examples more than offset the lower fixed costs.

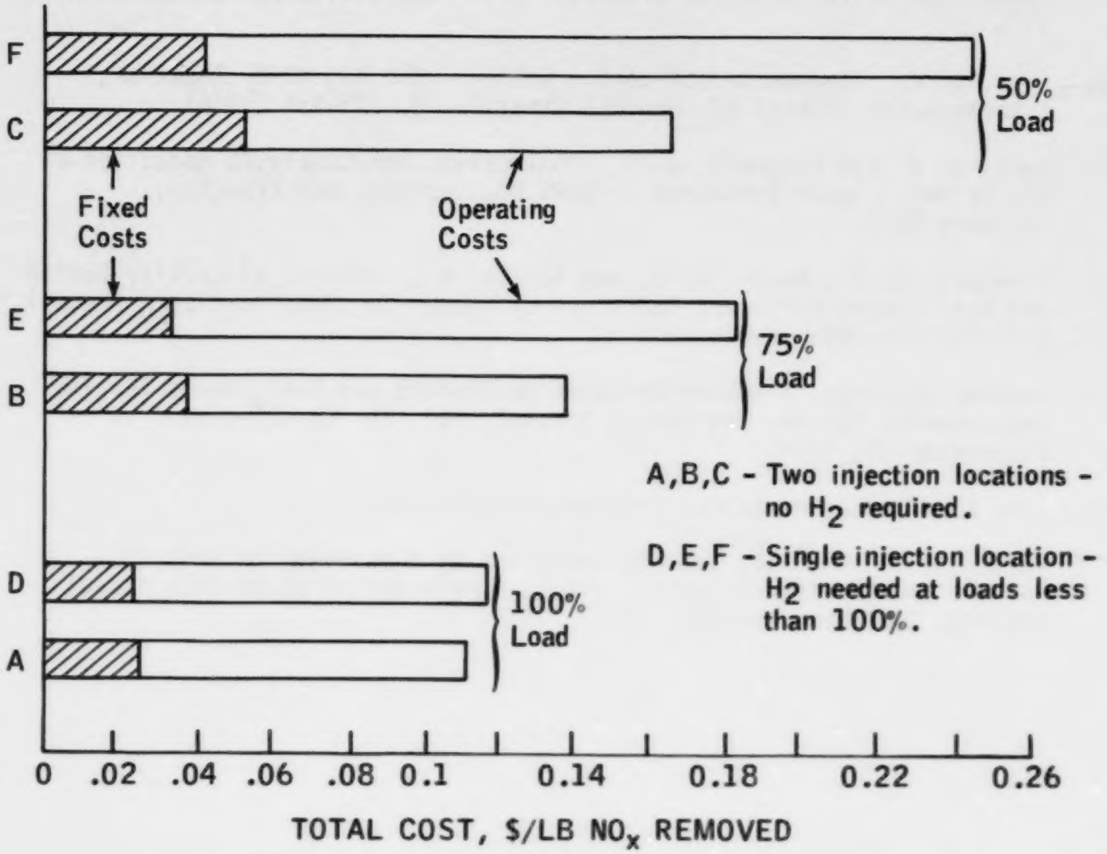

Figure 6-3 Comparison cost of injecting with and without H_2 in a Babcock and Wilcox - 333 MW Unit.

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APPENDIX 1

COST COMPARISON SUMMARY

This appendix provides a comparison of Thermal $DeNO_x$ process costs and the costs associated with combustion modifications for each full boiler load case studied.

THERMAL DENO$_x$ COST COMPARISON SUMMARY†

Case 1. Trim Target - Without Combustion Modifications

Unit		Initial NO$_x$ (ppm)	Target NO$_x$ (ppm)	Flue Gas Rate (k lb/hr)	NO$_x$ Reduction Required		NH$_3$/NOI (Molar Ratio)	Reagent Cost, \$/lbΔNO$_2$		
					(Percent)	(lb NO$_2$/hr)		Operating	Capital	Total
B&W	130 MW Subbituminous	500	375	1274	25	254	0.63	0.08	0.03	0.11
	333 MW Bituminous	700	450	2977	36	1189	0.76	0.07	0.009	0.08
	400 MW Lignite	1000	450	5046	55	4433	1.41	0.08	0.006	0.09
CE	350 MW Bituminous	500	450	3209	10	256	0.20	0.06	0.03	0.09
	800 MW Subbituminous	530	375	8671	29	2147	0.56	0.06	0.006	0.07
FW	330 MW Bituminous	850	450	3028	47	1935	1.24	0.08	0.008	0.09
	670 MW Subbituminous	700	375	8176	46	4244	0.98	0.07	0.005	0.08
RS	350 MW Bituminous	700	450	3942	36	1575	0.76	0.07	0.008	0.08

Unit		Reagent Cost - mills/kW-hr			Carrier Cost - mills/kW-hr			On-Site Cost	Total Thermal DeNO$_x$ Cost
		Operating	Capital	Total	Operating	Capital	Total	mills/kW-hr	mills/kW-hr
B&W	130 MW Subbituminous	0.16	0.06	0.22	0.08	0.11	0.19	0.08	0.49
	333 MW Bituminous	0.24	0.03	0.27	0.07	0.06	0.13	0.05	0.45
	400 MW Lignite	0.89	0.07	0.96	0.10	0.06	0.16	0.05	1.17
CE	350 MW Bituminous	0.05	0.02	0.07	0.07	0.06	0.13	0.05	0.25
	800 MW Subbituminous	0.16	0.02	0.18	0.09	0.03	0.12	0.04	0.34
FW	330 MW Bituminous	0.48	0.05	0.53	0.07	0.06	0.13	0.05	0.71
	670 MW Subbituminous	0.42	0.03	0.45	0.10	0.04	0.14	0.04	0.63
RS	350 MW Bituminous	0.30	0.04	0.34	0.09	0.06	0.15	0.05	0.54

† Thermal DeNO$_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

THERMAL DENO$_x$ COST COMPARISON SUMMARY†

Case 2. Trim Target With Combustion Modifications

	Unit	Initial NO$_x$ (ppm)	Target NO$_x$ (ppm)	Flue Gas Rate (k lb/hr)	NO$_x$ Reduction Required (Percent)	NO$_x$ Reduction Required (lb NO$_2$/hr)	NH$_3$/NO$_I$ (Molar Ratio)	Reagent Cost, $/lb NO$_2$ Operating	Reagent Cost, $/lb NO$_2$ Capital	Reagent Cost, $/lb NO$_2$ Total
B&W	130 MW Subbituminous	300	375		-	-	-	-	-	-
	333 MW Bituminous	420	450		-	-	-	-	-	-
	400 MW Lignite	900	450	5046	50	3627	1.24	0.08	0.006	0.09
CE	350 MW Bituminous	450	450		-	-	-	-	-	-
	800 MW Subbituminous	375	375		-	-	-	-	-	-
FW	330 MW Bituminous	510	450	3028	12	290	0.30	0.08	0.03	0.11
	670 MW Subbituminous	420	375	8176	11	588	0.24	0.07	0.02	0.09
RS	350 MW Bituminous	420	450		-	-	-	-	-	-

	Unit	Reagent Cost - mills/kW-hr Operating	Reagent Cost - mills/kW-hr Capital	Reagent Cost - mills/kW-hr Total	Carrier Cost - mills/kW-hr Operating	Carrier Cost - mills/kW-hr Capital	Carrier Cost - mills/kW-hr Total	On-Site Cost mills/kW-hr	Combustion Modification Technique	Combustion Modification Cost mills/kW-hr	Total Thermal DeNO$_x$ Cost mills/kW-hr	Total Cost mills/kW-hr
B&W	130 MW Subbituminous	-	-	-	-	-	-	-	LNB	0.06	-	0.06
	333 MW Bituminous	-	-	-	-	-	-	-	LNB	0.06	-	0.06
	400 MW Lignite	0.71	0.06	0.77	0.10	0.06	0.16	0.05	LEA	0.0	0.98	0.98
CE	350 MW Bituminous	-	-	-	-	-	-	-	OFA	0.08	-	0.08
	800 MW Subbituminous	-	-	-	-	-	-	-	OFA	0.08	-	0.08
FW	330 MW Bituminous	0.07	0.02	0.09	0.07	0.06	0.13	0.05	LNB	0.06	0.27	0.33
	670 MW Subbituminous	0.06	0.01	0.07	0.10	0.04	0.14	0.04	LNB	0.06	0.25	0.31
RS	350 MW Bituminous	-	-	-	-	-	-	-	OFA	0.10	-	0.10

† Thermal DeNO$_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

THERMAL DeNO$_x$ COST COMPARISON SUMMARY†

Case 3. Deep Reduction Target Without Combustion Modifications

Unit		Initial NO$_x$ (ppm)	Target NO$_x$ (ppm)	Flue Gas Rate (k lb/hr)	NO$_x$ Reduction Required		NH$_3$/NO$_I$ (Molar Ratio)	Reagent Cost, \$/lbΔNO$_2$		
					(Percent)	(lb NO$_2$/hr)		Operating	Capital	Total
B&W	130 MW Subbituminous	500	225	1274	55	-	-	-	-	-
	333 MW Bituminous	700	300	2977	57	1902	1.31	0.07	0.007	0.08
	400 MW Lignite	1000	300	5016	70	-	-	-	-	-
CE	350 MW Bituminous	500	300	3209	40	1025	.76	0.06	0.01	0.07
	800 MW Subbituminous	530	225	8671	58	4224	1.5	0.08	0.006	0.09
FW	330 MW Bituminous	850	300	3028	65	-	-	-	-	-
	670 MW Subbituminous	700	225	8176	88	-	-	-	-	-
RS	350 MW Bituminous	700	300	3942	57	2519	1.46	0.08	0.007	0.09

Unit		Reagent Cost - mills/kW-hr			Carrier Cost - mills/kW-hr			On-Site Cost	Total Thermal DeNO$_x$ Cost
		Operating	Capital	Total	Operating	Capital	Total	mills/kW-hr	mills/kW-hr
B&W	130 MW Subbituminous	-	-	-	-	-	-	-	-
	333 MW Bituminous	0.41	0.40	0.45	0.07	0.06	0.13	0.05	0.63
	400 MW Lignite	-	-	-	-	-	-	-	-
CE	350 MW Bituminous	0.17	0.03	0.20	0.07	0.06	0.13	0.05	0.38
	800 MW Subbituminous	0.43	0.03	0.46	0.09	0.03	0.12	0.04	0.62
FW	330 MW Bituminous	-	-	-	-	-	-	-	-
	670 MW Subbituminous	-	-	-	-	-	-	-	-
RS	350 MW Bituminous	0.58	0.05	0.63	0.09	0.06	0.15	0.05	0.83

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† Thermal DeNO$_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

THERMAL DeNO$_x$ COST COMPARISON SUMMARY+

Case 4. Deep Reduction Target With Combustion Modifications

	Unit	Initial NO$_x$ (ppm)	Target NO$_x$ (ppm)	Flue Gas Rate (k lb/hr)	NO$_x$ Reduction Required (Percent)	NO$_x$ Reduction Required (lb NO$_2$/hr)	NH$_3$/NO$_I$ (Molar Ratio)	Reagent Cost, \$/lbΔNO$_2$ Operating	Reagent Cost, \$/lbΔNO$_2$ Capital	Reagent Cost, \$/lbΔNO$_2$ Total
B&W	130 MW Subbituninous	300	225	1274	25	153	0.63	0.08	0.05	0.13
	333 MW Bituminous	420	300	2977	29	571	0.61	0.07	0.02	0.09
	400 MW Lignite	900	300	5046	67	-	-	-	-	-
CE	350 MW Bituminous	450	300	3209	33	769	0.64	0.06	0.01	0.07
	800 MW Subbituminous	375	225	8671	40	2077	0.77	0.06	0.006	0.07
FW	330 MW Bituminous	510	300	3028	41	1016	1.00	0.08	0.01	0.09
	670 MW Subbituminous	420	225	8176	46	2546	0.98	0.07	0.006	0.08
RS	350 MW Bituminous	420	300	3942	29	756	0.62	0.07	0.01	0.08

	Unit	Reagent Cost - mills/kW-hr Operating	Reagent Cost - mills/kW-hr Capital	Reagent Cost - mills/kW-hr Total	Carrier Cost - mills/kW-hr Operating	Carrier Cost - mills/kW-hr Capital	Carrier Cost - mills/kW-hr Total	On-Site Cost mills/kW-hr	Combustion Modification Technique	Combustion Modification Cost mills/kW-hr	Total Thermal DeNO$_x$ Cost mills/kW-hr	Total Cost mills/kW-hr
B&W	130 MW Subbituminous	0.09	0.05	0.14	0.08	0.11	0.19	0.08	LNB	0.06	0.41	0.47
	333 MW Bituminous	0.11	0.03	0.14	0.07	0.06	0.13	0.05	LNB	0.06	0.32	0.38
	400 MW Lignite	-	-	-	-	-	-	-	LEA	0.0	-	-
CE	350 MW Bituminous	0.13	0.03	0.16	0.07	0.06	0.13	0.05	OFA	0.08	0.34	0.42
	800 MW Subbituminous	0.16	0.02	0.18	0.09	0.03	0.12	0.04	OFA	0.08	0.34	0.42
FW	330 MW Bituminous	0.23	0.03	0.26	0.07	0.06	0.13	0.05	LNB	0.06	0.44	0.50
	670 MW Subbituminous	0.25	0.02	0.27	0.10	0.04	0.14	0.04	LNB	0.06	0.45	0.51
RS	350 MW Bituminous	0.15	0.03	0.18	0.09	0.06	0.15	0.05	OFA	0.10	0.38	0.48

+ Thermal DeNO$_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

THERMAL DeNO$_x$ COST COMPARISON SUMMARY+

Case 5. Maximum DeNO$_x$ at NH_3/NO_I = 1.5 Without Combustion Modifications

Unit		Initial NO$_x$ (ppm)	Target NO$_x$ (ppm)	Flue Gas Rate (k lb/hr)	NO$_x$ Reduction Required (Percent)	NO$_x$ Reduction Required (lb NO_2/hr)	NH_3/NO_I (Molar Ratio)	Reagent Cost, \$/lbΔNO_2 Operating	Reagent Cost, \$/lbΔNO_2 Capital	Reagent Cost, \$/lbΔNO_2 Total
B&W	130 MW Subbituminous	500	250	1274	50	509	1.5	0.09	0.02	0.11
	333 MW Bituminous	700	291	2977	63	1945	1.5	0.08	0.008	0.09
	400 MW Lignite	1000	430	5046	57	4594	1.5	0.08	0.006	0.09
CE	350 MW Bituminous	500	210	3209	58	1486	1.5	0.08	0.008	0.09
	800 MW Subbituminous	530	228	8671	57	4183	1.5	0.08	0.006	0.09
FW	330 MW Bituminous	850	391	3028	54	2220	1.5	0.09	0.008	0.10
	670 MW Subbituminous	700	280	8176	60	5484	1.5	0.08	0.006	0.09
RS	350 MW Bituminous	700	294	3942	58	2556	1.5	0.08	0.007	0.09

Unit		Reagent Cost - mills/kW-hr Operating	Reagent Cost - mills/kW-hr Capital	Reagent Cost - mills/kW-hr Total	Carrier Cost - mills/kW-hr Operating	Carrier Cost - mills/kW-hr Capital	Carrier Cost - mills/kW-hr Total	On-Site Cost mills/kW-hr	Total Thermal DeNO$_x$ Cost mills/kW-hr
B&W	130 MW Subbituminous	0.37	0.07	0.44	0.08	0.11	0.19	0.08	0.71
	333 MW Bituminous	0.47	0.04	0.52	0.07	0.06	0.13	0.05	0.70
	400 MW Lignite	0.95	0.07	1.02	0.10	0.06	0.16	0.05	1.23
CE	350 MW Bituminous	0.35	0.04	0.39	0.07	0.06	0.13	0.05	0.57
	800 MW Subbituminous	0.43	0.03	0.46	0.09	0.03	0.12	0.04	0.62
FW	330 MW Bituminous	0.59	0.05	0.64	0.07	0.06	0.13	0.05	0.82
	670 MW Subbituminous	0.64	0.05	0.69	0.10	0.04	0.14	0.04	0.87
RS	350 MW Bituminous	0.59	0.05	0.64	0.09	0.06	0.15	0.05	0.84

+ Thermal DeNO$_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

THERMAL DENO$_x$ COST COMPARISON SUMMARY†

Case 6. Maximum DeNO$_x$ at NH$_3$/NO$_I$ = 1.5 With Combustion Modifications

Unit		Initial NO$_x$ (ppm)	Target NO$_x$ (ppm)	Flue Gas Rate (k lb/hr)	NO$_x$ Reduction Required		NH3/NO$_I$ (Molar Ratio)	Reagent Cost, \$/lb NO$_2$		
					(Percent)	(lb NO$_2$/hr)		Operating	Capital	Total
B&W	130 MW Subbituminous	300	150	1274	50	305	1.5	0.10	0.03	0.13
	333 MW Bituminous	420	175	2977	63	1165	1.5	0.08	0.01	0.09
	400 MW Lignite	900	387	5016	57	4135	1.5	0.08	0.006	0.09
CE	350 MW Bituminous	450	189	3209	58	1292	1.5	0.08	0.009	0.09
	800 MW Subbituminous	375	161	8671	57	2964	1.5	0.08	0.007	0.09
FW	330 MW Bituminous	510	234	3028	54	1335	1.5	0.09	0.01	0.10
	670 MW Subbituminous	420	168	8176	60	3291	1.5	0.08	0.006	0.09
RS	350 MW Bituminous	420	176	3942	58	1536	1.5	0.08	0.009	0.09

Unit		Reagent Cost - mills/kW-hr			Carrier Cost - mills/kW-hr			On-Site Cost	Combustion Modification Technique	Combustion Modification Cost	Total Thermal DeNO$_x$ Cost	Total Cost
		Operating	Capital	Total	Operating	Capital	Total	mills/kW-hr		mills/kW-hr	mills/kW-hr	mills/kW-hr
B&W	130 MW Subbituminous	0.22	0.06	0.28	0.08	0.11	0.19	0.08	LNB	0.06	0.55	0.61
	333 MW Bituminous	0.28	0.04	0.32	0.07	0.06	0.13	0.05	LNB	0.06	0.50	0.56
	400 MW Lignite	0.86	0.07	0.92	0.10	0.06	0.16	0.05	LEA	0.0	1.13	1.13
CE	350 MW Bituminous	0.31	0.04	0.35	0.07	0.06	0.13	0.05	OFA	0.08	0.53	0.61
	800 MW Subbituminous	0.31	0.02	0.33	0.09	0.03	0.12	0.04	OFA	0.08	0.49	0.57
FW	330 MW Bituminous	0.35	0.04	0.39	0.07	0.06	0.13	0.05	LNB	0.06	0.57	0.63
	670 MW Subbituminous	0.39	0.03	0.42	0.10	0.04	0.14	0.04	LNB	0.06	0.60	0.66
RS	350 MW Bituminous	0.35	0.04	0.39	0.09	0.06	0.15	0.05	OFA	0.10	0.59	0.69

† Thermal DeNO$_x$ costs do not include licensing fees and charges for preliminary engineering and testing.

APPENDIX 2

Noncatalytic NO_x Removal With Ammonia

FP-735
Research Project 835-1

Final Report, April 1978

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ABSTRACT

A potential approach to the control of nitric oxide in utility boilers, in addition to modification of the combustion process, is the selective homogeneous gas-phase reduction of nitric oxide with ammonia. A laboratory study at a scale of 3,000,000 Btu/hr was conducted to evaluate the applicability of ammonia injection for the reduction of nitric oxide in coal-fired power plants. Four coals (Utah bituminous, New Mexico subbituminous, Illinois bituminous, and Pittsburgh bituminous) were tested to determine levels of NOx reductions achievable and the byproduct emissions. The primary variables investigated (in addition to coal type) were (1) the amount of ammonia injected, and (2) the temperature of the combustion products at the point of injection. The effect of the simultaneous addition of hydrogen along with ammonia on the NOx removal process was also investigated. The results of these experiments indicated that NO reductions obtained with ammonia injection into coal-derived combustion products were similar to those obtained with natural gas firing in the same system and were comparable to those previously obtained in natural gas and oil-fired systems. On the order of 65% reductions in NO were obtained at an ammonia injection rate of one mole of ammonia per mole of NO. However, the temperature dependence was found to vary from coal to coal. The Navaho exhibited peak reductions at the lowest temperatures, 1720 °F, while the Illinois coal showed peak reduction occurring at 1830 °F. Typically, natural gas exhibited peak reductions at 1750 °F. The unexplained variation in optimum process temperature with coal type indicates that evaluation testing would be prudent in situations where maximum NOx control was desired and no previous experience was available for the coal in question. The simultaneous addition of small quantities of hydrogen can be used to increase the NO reductions and decrease ammonia emissions at temperatures lower than the optimum.

ACKNOWLEDGEMENTS

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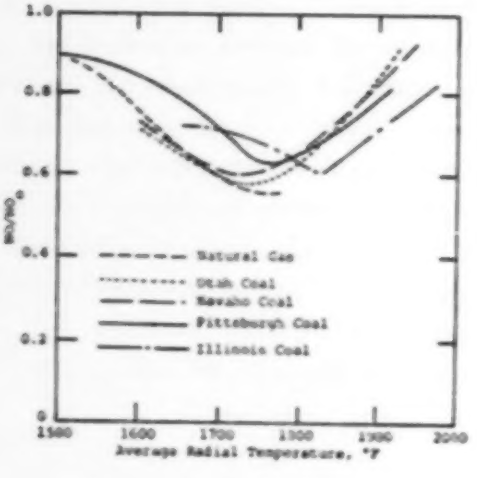
EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency has published research goals for the emissions of nitric oxide from stationary sources which would limit flue gas concentrations to 100 ppm from coal-fired power plants by 1985 (Ref. 1). Numerous approaches are being evaluated for controlling NOx emissions from stationary combustion sources. These approaches cover the spectrum from "front end" control of the combustion process to the physical or chemical removal of the oxides of nitrogen in the downstream regions of the unit. One potentially attractive process for coal-fired utility boilers entails the selective gas-phase decomposition of nitric oxide by ammonia. In this process, ammonia is injected into the combustion products. If the temperature of the combustion products is between 1200 °F and 2000 °F, the ammonia will selectively react with the nitric oxide in the presence of excess oxygen to form primarily nitrogen and water. However, nitric oxide reductions on the order of 50% or greater occur in the vicinity of 1750 °F (± 100 °F). Hydrogen can be used along with the ammonia to lower the temperature at which the selective reduction occurs. A patent is held by the Exxon Research and Engineering Company on this process (Ref. 2).

While a significant amount of data have been gathered on the selective reduction of NOx in oil- and gas-fired systems, little information is currently available as to the applicability of the process to coal-fired systems. In particular, the levels of NOx reductions achievable, the byproduct emissions, and the possible catalytic interaction due to the coal ash with NH_3 injection into coal-derived combustions have not been characterized. A laboratory study was conducted at a scale of 3,000,000 Btu/hr to evaluate the applicability of NH_3 injection to coal-firing systems. The specific objectives of the study were to: (1) Determine the levels of NOx removal and ammonia emissions with ammonia injection into the combustion products resulting from pulverized coal combustion; (2) Determine the type and levels of byproduct emissions: (SO_2, SO_3, CO, HCN, NH_3, unburned hydrocarbons, nitrate particulates, and sulfate particulates); (3) Determine any effects that varying coal types might have on the process. A variety of coals were represented in the study (Utah bituminous, Navaho sibbituminous, Pittsburgh Seam 8 bituminous, and Illinois bituminous); and (4) Determine the extent to which hydrogen can lower the temperature at which NH_3 would remove NOx from coal-derived combustion products.

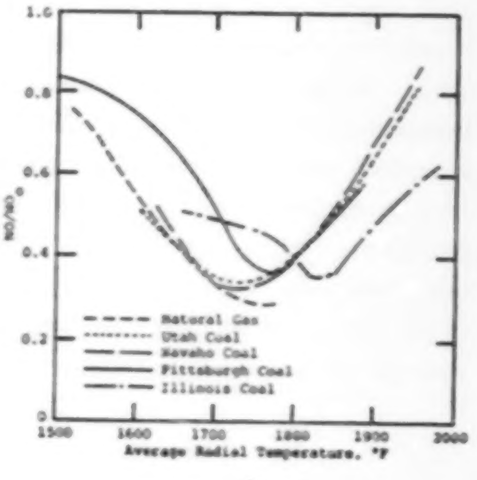
The basis of the experimental system was a firetube boiler modified to fire pulverized coal with preheated combustion air (600 °F). The burner was a geometrically scaled version of a burner currently in use in a coal-fired utility boiler in the western United States. The ammonia was injected with a carrier stream of nitrogen through five water-cooled injectors in the main firetube (33 in. diameter). The temperature at the point of injection was controlled by (1) moving the injectors axially in the firetube, (2) changing the heat removal rate from the main firetube with stainless steel liners, and (3) varying firing rate.

A summary of the nitric oxide reductions obtained for all fuels tested during this study is shown in the two figures below.



A.

$(NH_3/NO)_o = 0.5$, Excess $O_2 \sim 5.0\%$)



B.

$(NH_3/NO)_o = 1.0$, Excess $O_2 \sim 5.0\%$)

NO reductions obtained with ammonia injection during this study were similar for all fuels tested. At the optimum temperature, on the order of 65% reductions in NO were obtained at an ammonia injection rate of one mole of ammonia per mole of NO for all fuels. However, the temperature dependence varied from coal to coal. The Navaho exhibited peak reductions at the lowest temperature, 1720 °F, while the Illinois coal showed peak reductions occurring at 1830 °F. The optimum temperature for natural gas was 1750 °F. A very limited series of tests was conducted to determine the cause of the variation in optimum temperature, however no definitive reason could be found to explain this temperature variation. The unexplained variation in optimum process temperature with coal type indicates that evaluation testing would be prudent in situations where maximum NOx control was desired and no previous experience was available for the coal in question.

In general, the ammonia breakthrough emissions are comparable for all the fuels tested during this program. The highest emissions of ammonia occurred when the temperature of the combustion products at the point of injection was less than that required for optimum NO removal. With judicious selection of the temperature at the point of injection, it was possible to achieve nitric oxide reductions of 55% while limiting NH_3 emissions to the range of 10 to 35 ppm (for reference purposes, the odor level of ammonia is commonly stated to be 50 ppm).

With ammonia injection, no statistically significant changes in the cyanide and nitrate species concentrations were measured relative to the baseline case of no ammonia injection. This supports previous studies (Refs. 3, 4) that cyanide and nitrates are not byproducts of the selective homogeneous reduction process. The primary products of the NOx removal process are molecular nitrogen (N_2) and water (H_2O).

The SO_3 levels in the flue gas tended to be lower when ammonia was injected to reduce the oxides of nitrogen; this suggests sulfate producing reactions between NH_3 and SO_3. Quantitative variations in sulfate levels with ammonia injection were somewhat inconclusive as only small changes were measured. However, SO_3 levels were reduced for each of the coals tested. Further clarification of this point would seem warranted.

The experiments while firing the Pittsburgh seam coal further confirmed that the addition of small quantities of hydrogen injected along with ammonia can be used to increase the NO reductions and decrease the ammonia emissions at lower temperatures than observed without hydrogen injection. At a given temperature and ammonia injection rate, there exists an optimum rate of hydrogen injection. Further increase in the hydrogen injection rate results in decreases in the amount of NO removed. This optimum hydrogen rate increases as the temperature at the point of injection decreases.

With the exception of the variation in optimal process temperature with coal type, the findings with NH_3 injection into coal-derived combustion products are in substantial agreement with previous experimental results for gas and oil-fired systems (Refs. 3, 4) in terms of achievable NO reduction, ammonia emissions, and byproduct formation.

SECTION 1.0

INTRODUCTION AND OBJECTIVES

1.1 BACKGROUND

Numerous approaches are being considered for controlling NOx emissions from stationary combustion sources. These approaches cover the spectrum from "front end" control of the combustion process to the physical or chemical removal of the oxides of nitrogen in the downstream regions of the unit. A process that appears to be attractive for control of NOx emissions from coal-fired utility boilers entails the selective gas phase decomposition of nitric oxide by ammonia. In this process, ammonia is injected into the combustion products; if the temperature of the combustion products is between 1200 °F and 2000 °F, the ammonia will selectively react with the nitric oxide in the presence of excess oxygen to form nitrogen and water vapor. However, nitric oxide reductions on the order of 50% or greater occur in the vicinity of 1750 °F (± 100 °F). A patent is held by the Exxon Research and Engineering Company on this process (Refs. 2, 3).

Previously, EPRI sponsored a program to investigate the potential for the gas phase reduction of NOx in utility boilers (Refs. 4, 5). During this study a small natural gas-fired combustion tunnel was used to determine the conditions of concentration, temperature, and reducing agent type which would result in the selective reduction of NOx in the presence of varying amounts of oxygen and nitric oxide. A selective reduction of NOx was found to occur when ammonia was injected into combustion products which were at a temperature from 1300 °F to 2000 °F with peak reductions occurring in a narrow temperature region about 1750 °F. Typical results which were obtained in this gas-fired combustion tunnel in terms of the effect of temperature and the amount of ammonia which was injected are shown in Figure 1. As can be seen from this figure, approximately 80% of the NOx is removed when one mole of NH_3 is injected for every mole of NOx initially present.

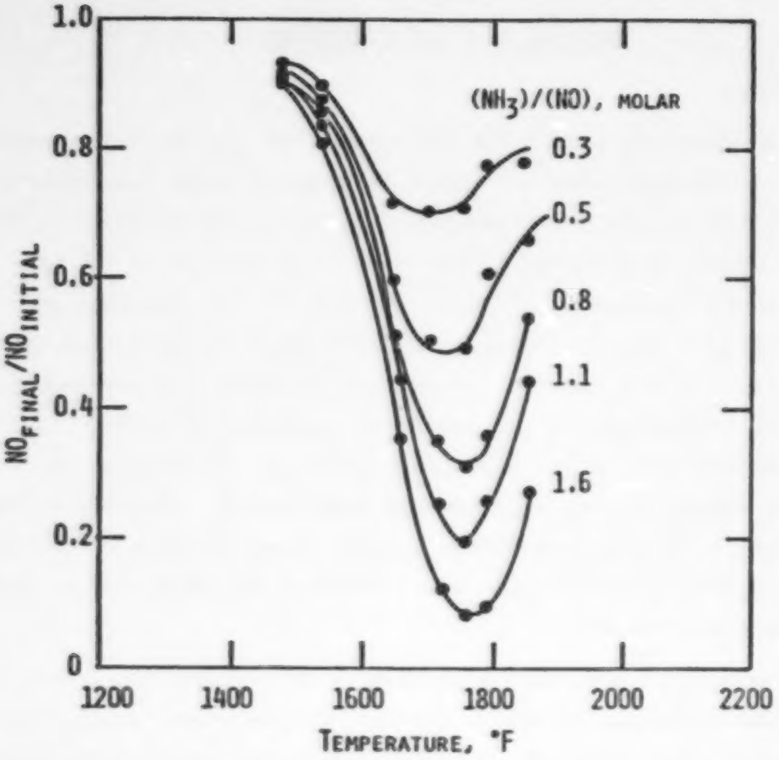


Figure 1. Effect of temperature on NO reductions with ammonia injection. (Excess oxygen 4%, initial NO 300 ppm, Ref. 4)

Exxon Research and Engineering (the patent holder for the process) has also done an extensive amount of proprietary development work on this process. In fact, the process has been applied to a number of oil- and gas-fired industrial boilers and process heaters in Japan.

1.2 OBJECTIVES

While a significant amount of data has been gathered on the selective reduction of NOx in oil- and gas-fired systems, little information is currently available as to the applicability of the process to coal-fired power plants. In particular, the levels of NOx reductions which are achievable and the associated byproduct emissions, as well as the possible catalytic or other effects due to the coal ash and the injected ammonia must be developed.

The specific objectives of the study involved the

- Determination of the levels of NOx removal and ammonia emissions with ammonia injection into the combustion products resulting from pulverized coal combustion. The primary variables of the study were the temperature at the point of NH_3 injection, the amount of NH_3 injected, and the coal type.
- Determination of the type and levels of byproduct emissions. In particular the following were determined: SO_2, SO_3, CO, CN, NH_3, unburned hydrocarbons, nitrate particulates, sulfate particulates.
- Determination of any effects that varying coal types might have on the process. A variety of coals were used in the study including: a Utah bituminous, a Navaho subbituminous, Pittsburgh Seam 8 bituminous and an Illinois bituminous. The results are compared to the NOx emissions obtained with natural gas.
- Determination of the extent to which hydrogen can lower the temperature at which NH_3 would remove NOx from coal derived combustion products and to determine the effect of H_2 on the ammonia emissions at various temperature levels.

SECTION 2.0

EXPERIMENTAL APPROACH AND APPARATUS

2.1 APPROACH

The objectives of the present program were accomplished through a systematic series of experiments conducted in a pulverized coal combustion facility capable of firing at rates up to approximately 3,000,000 Btu/hr (nominally 250 lb/hr coal feed). A description of the combustion facility as well as the instrumentation employed and the experimental procedure comprises the remainder of this section.

2.2 COMBUSTION FACILITY

The combustion facility used in this program had the capability of firing either natural gas or pulverized coal. A schematic diagram of the facility is shown in Figure 2.

2.2.1 Combustor

The basic combustion facility consisted of a firetube boiler which was modified to fire pulverized coal. A detailed description of the boiler and auxiliary equipment is contained in Appendix A.

Stainless steel liners were installed in the main firetube as a means of varying the gas temperatures at the point of ammonia injection (e.g., lower gas temperatures were attained by removing sections of the liners).

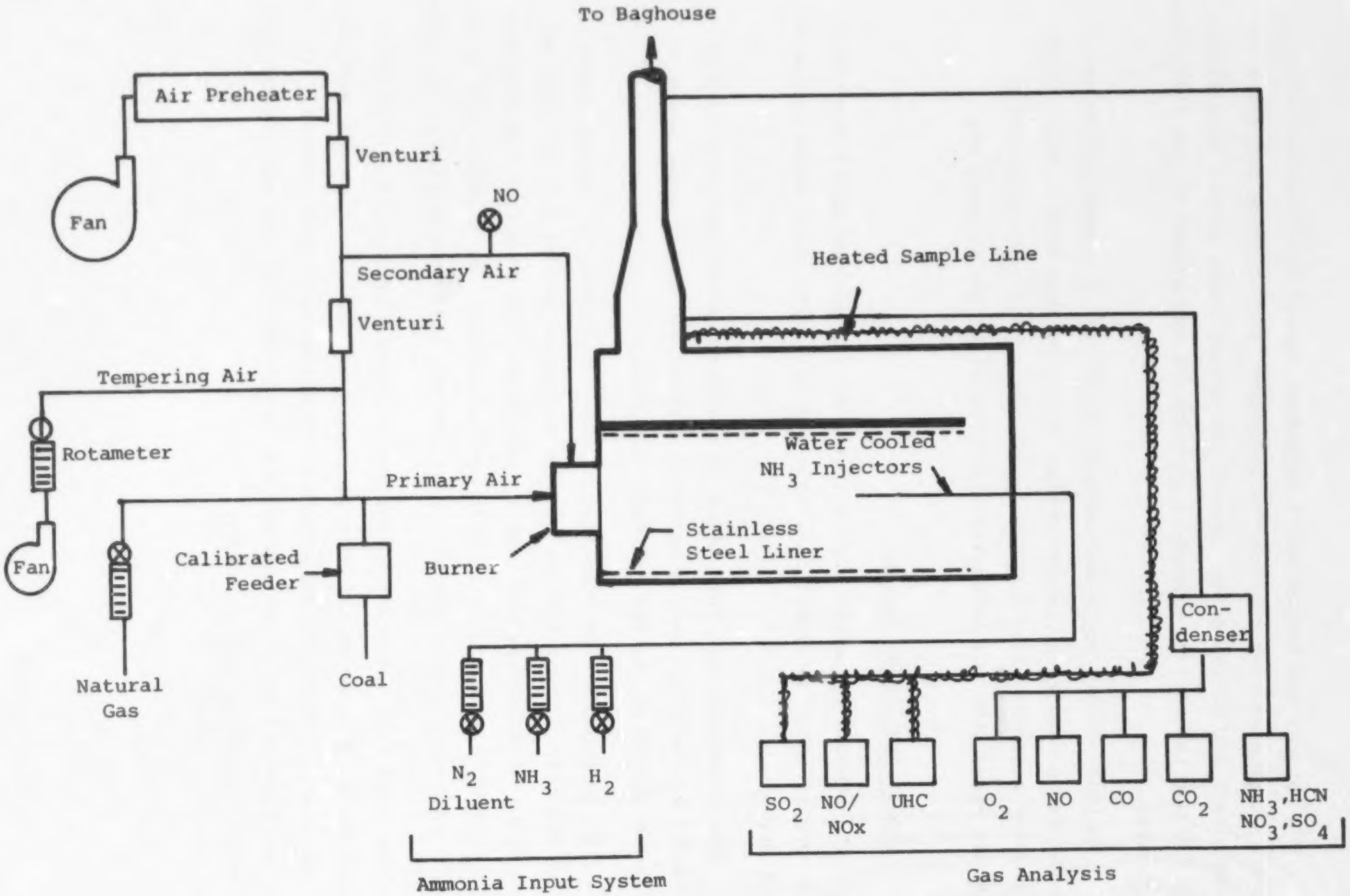

To Baghouse
Air Preheater
Fan
Venturi
NO
Secondary Air
Venturi
Tempering Air
Rotameter
Fan
Primary Air
Heated Sample Line
Water Cooled
NH3 Injectors
Stainless
Steel Liner
Burner
Calibrated
Feeder
Natural
Gas
Coal
Con-
denser
N2
Diluent
NH3
H2
Ammonia Input System
SO2
NO/
NOx
UHC
O2
NO
CO
CO2
NH3,HCN
NO3,SO4
Gas Analysis

Figure 2. Schematic diagram of combustion facility.

The natural gas burner was a ring-type burner with a single air register. During some of the natural gas tests, nitric oxide was added to the combustion air to raise the exhaust gas nitric oxide levels to approximately 500 ppm in order to provide a more direct comparison to the coal-fired test results.

The coal burner was a scaled-down version of a commercial burner presently being used in a utility boiler firing western coal. This burner incorporated a single adjustable air register and the primary air/coal stream was mixed with the secondary air by swirling the primary mixture.

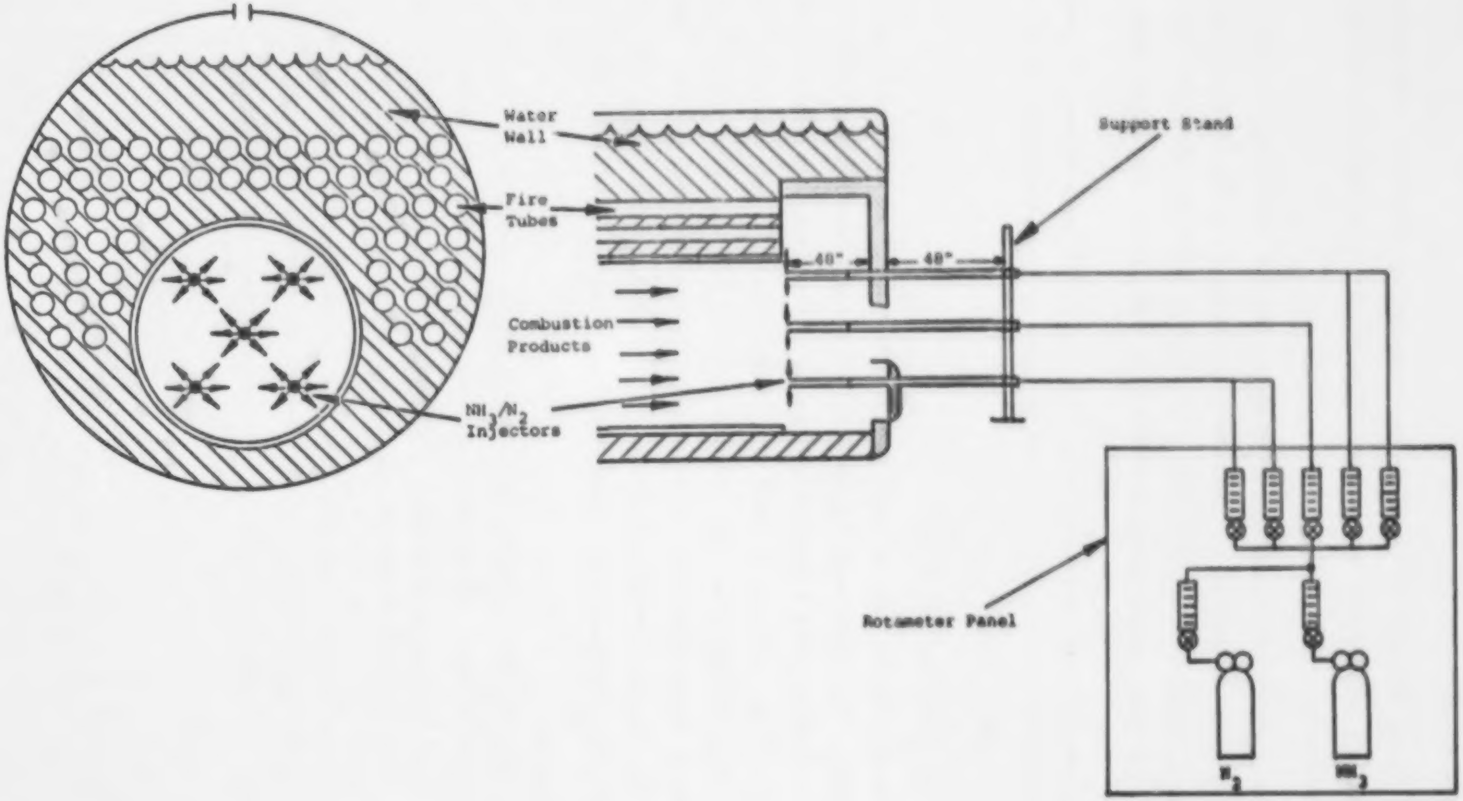
2.2.2 Ammonia Injection System

The ammonia injectors were designed to (1) provide rapid dispersion of the ammonia into the combustion products, (2) allow axial positioning in the boiler.

The injectors were fabricated of stainless steel and water cooled. The ammonia was injected with a nitrogen carrier gas to increase the penetration and mixing of the ammonia with the combustion products.

The injector system schematic is shown in Figure 3. It was found early in the testing that the use of five injection points was the most effective means of achieving the best NO reductions and therefore the majority of the tests were conducted with this configuration. For a commercial application, a more extensive optimization of the NH_3 injection system is warranted.

The mass flow rate of the injected nitrogen, ammonia, and hydrogen were measured by rotameters as shown in Figure 4. The five separate ammonia rotameters downstream of the main ammonia rotameter were used primarily to balance the flows to the injectors and the total ammonia flow was determined by the most accurate single rotameter.



Water Wall
Fire Tubes
Combustion Products
NH_3/N_2 Injectors
48"
48"
Support Stand
Rotameter Panel
N_2
NH_3

Figure 3. 80 HP boiler ammonia injection schematic.

70<

2.3 INSTRUMENTATION

All air flows and gas flows into the combustion facility were measured either by calibrated rotameters or venturi flow meters. A complete description is given in Appendix A.

Since the combustion product temperature and the level of excess oxygen level were the primary variables of interest, no effort was made to accurately calibrate the coal feeder. Instead, the coal firing rate was deduced from the coal analysis, flue gas oxygen concentration and combustion air flow rate.

Low temperature measurements were made using chromel-alumel thermocouples. Gas temperatures in the combustion section were measured using an aspirated thermocouple probe.

2.3.1 Aspirated Temperature Probe

An aspirated Pt-Pt/10% Rh thermocouple was used to obtain the temperature profile data. The aspirated thermocouple is used to minimize radiation losses. In this device, the thermocouple is isolated from the surroundings through a series of concentric ceramic radiation shields. At the same time, the convective heat transfer to the thermocouple is increased by aspirating the hot combustion gases past the thermocouple and radiation shields. The probe used in the study is shown in Figure 5 and is a slightly modified design as used by the International Flame Research Foundation (IFRF) (Ref. 6).

2.3.2 Gas Analysis

The chemical analysis performed during these experiments included a wide variety of techniques. Continuous gas analyzers were used to measure excess oxygen (O_2), oxides of nitrogen (NO/NOx), carbon monoxide (CO), carbon dioxide (CO_2), unburned hydrocarbons (UHC), and sulfur dioxide (SO_2).

Batch techniques were utilized for the determination of ammonia (NH_3), cyanide (CN), sulfur trioxide, sulfates, and nitrates. The ammonia, cyanide, and nitrate species were bubbled through appropriate

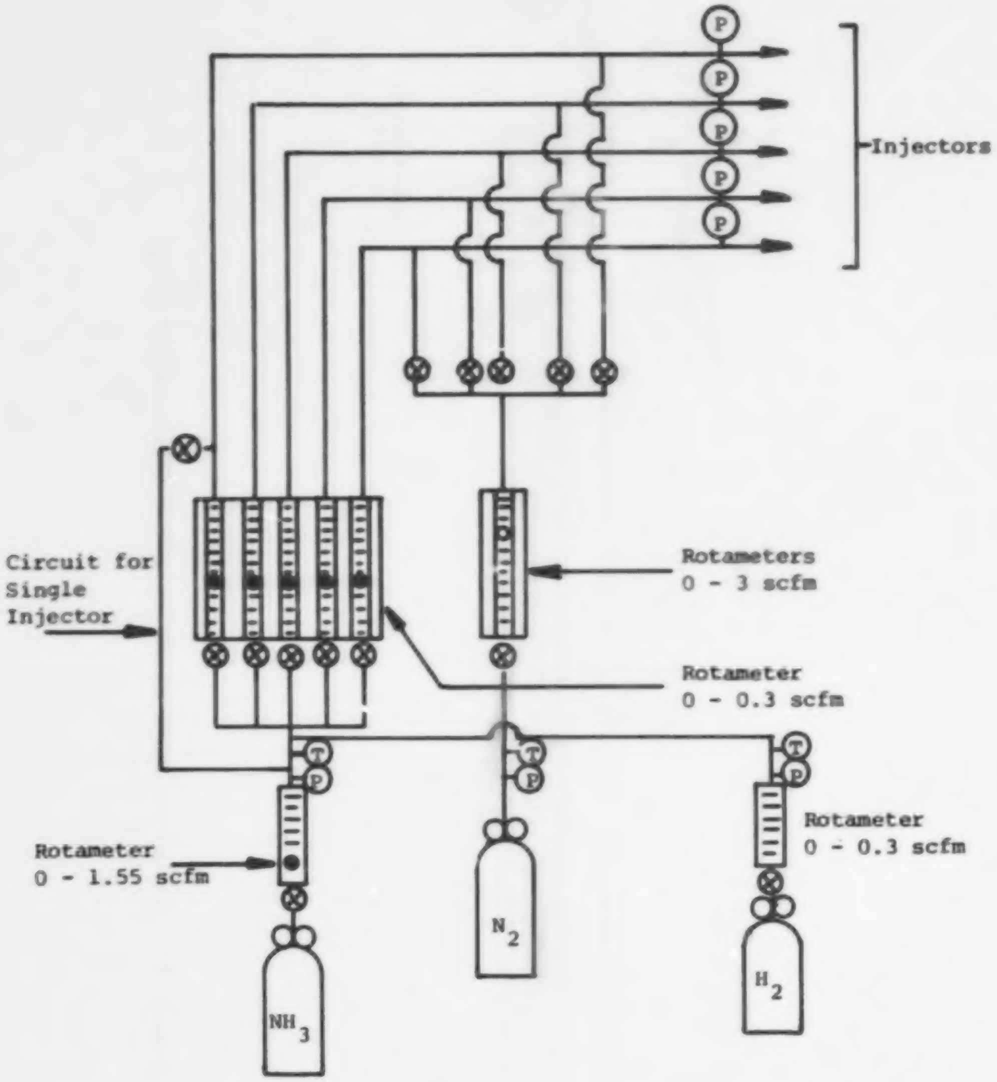

P
P
P
P
P
Injectors
Circuit for Single Injector
Rotameters 0 - 3 scfm
Rotameter 0 - 0.3 scfm
T
P
T
P
T
P
Rotameter 0 - 1.55 scfm
Rotameter 0 - 0.3 scfm
N_2
H_2
NH_3

Figure 4. Ammonia injection flowmeters.

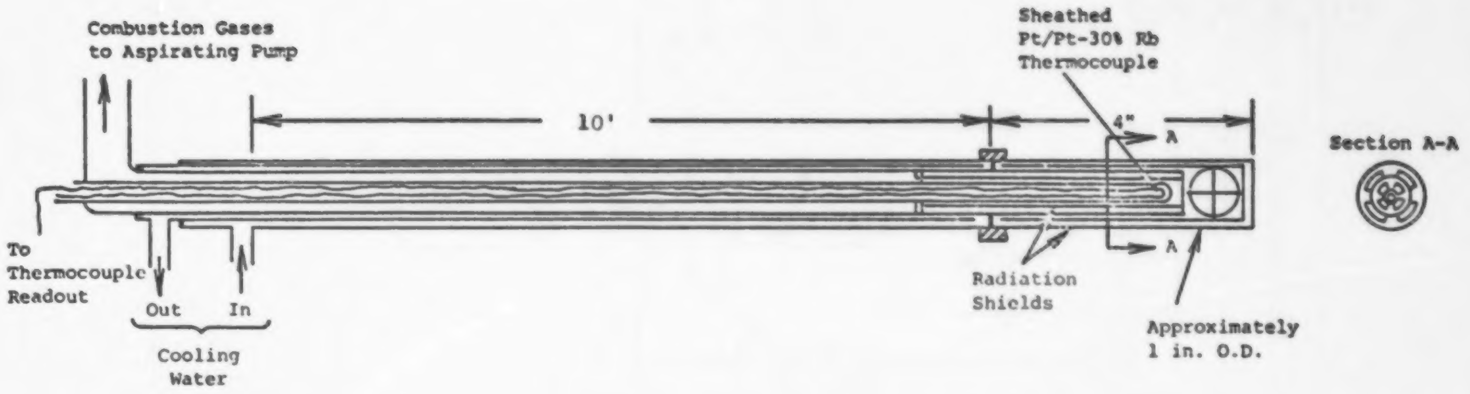

Combustion Gases
to Aspirating Pump
Sheathed
Pt/Pt-30% Rb
Thermocouple
10'
4"
A
A
Section A-A
To
Thermocouple
Readout
Out
In
Cooling
Water
Radiation
Shields
Approximately
1 in. O.D.

Figure 5. Schematic Diagram of Aspirated Thermocouple Probe.
(Not to Scale.)

absorbing solutions -- dilute sulfur acid for ammonia, sodium hydroxide for cyanide, and distilled water for nitrates. The resultant solution and the probe and sample line washings were then analyzed using specific ion electrodes. A summary of the gas analysis instrumentation is presented in Table 1. Further details of the instrumentation and procedures for the determination of ammonia, cyano, and nitrate is contained in Reference 4.

Sulfates and SO_3 were determined by a procedure outlined by R. K. Lyon of Exxon Research and Engineering (Ref. 7). The sulfate was collected by sampling the combustion products with a heated quartz probe and collecting the sample on a heated filter maintained at 310 °F. A gravimetric procedure was used for the sulfate analysis. The SO_3 concentration was determined by using the sulfate sampling system and adding an excess of ammonia to the probe. It was assumed that the excess ammonia injected into the probe reacted with the free SO_3 in the sample to form a sulfate. The difference between the sulfate levels with and without ammonia injected into the sampling probe is taken to be the SO_3 concentration in the sample. Appendix B contains a more detailed description of the procedure for sulfate and SO_3 determination.

TABLE 1. GAS ANALYSIS INSTRUMENTATION

Species	Analyzer
NO/NO_2	TECO Model 10A Chemiluminescent (molybdenum converter)
O_2	Beckman Model 742 Electrolytic
CO	Horiba Model PIR 2000 NDIR
CO_2	Horiba Model AIA 21 NDIR
UHC	Beckman Model 402 Flame Ionization Detector
SO_2	Du Pont Model 401 Photometric
NH_3	Orion 95-10 Specific Ion Electrode (701 Meter)
CN	Orion 94-06 Specific Ion Electrode (701 Meter)
NO_3	Orion 93-07 Specific Ion Electrode (701 Meter)
SO_4	Gravimetric Analysis of filter catch
SO_3	Gravimetric Analysis following conversion to sulfate

2.4 EXPERIMENTAL PROCEDURE AND TEST MATRIX

2.4.1 Experimental Procedure

One of the primary parameters of interest was the combustion product temperature at the point of ammonia injection. It was found that in order to obtain the temperature range of 1500 to 2000 °F within the main firetube the boiler had to be fired at a rate of approximately 1.5 to 2.0 million Btu per hour. At this rate it required approximately one and one-half hours for the boiler to stabilize before sampling could begin. Temperatures at the point of NH_3 injection could be varied 300 °F by simply changing the axial position of the injectors while maintaining all other test conditions constant. Removal of the stainless steel heat shields from the main firetube provided further variation in temperature. By the combination of heat shield removal and change in axial location of the NH_3 injectors, the temperature range of approximately 1600 to 1950 °F was available.

Normally, temperature measurements were made during this warm-up period to establish the point at which the boiler was stable and also to enable projections of the rate of changes of the gas temperature with time. This was necessary since ash accumulation in the combustion section acted as insulation and resulted in a continuous increase in temperature on the order of one-half degree per minute after the initial warm-up period. The gas temperature was also measured after each set of data to establish the temperature-time history during the test period. Interpolation of this temperature time history was used to determine the combustion product temperature at the point of ammonia injection.

This increase in temperature with time complicated the determination of the exact temperature at the point of NH_3 injection. The following procedure was adopted. The boiler was fired and the excess air set to yield approximately 5% excess oxygen at the firing rate which produced the desired temperature range. These conditions were not changed during a test. The aspirated thermocouple was inserted and the temperature of the gas along the boiler centerline, was monitored until the rate of change approached

1/2 °F per minute. Once this condition was achieved temperatures were recorded at the various axial locations to determine the temperature range available. Baseline NH_3, HCN, and NO_3 emissions were taken during this time. The probe was then removed and the ammonia injectors were inserted to the axial plane which yielded the desired test temperature. An NH_3 injection rate was then set and all sampling commenced; the NH_3, CN, and NO_3 samples were taken concurrent with the continuous analyzer data of O_2, NO, NOx, CO, CO_2, UHC, and SO_2.

After all NH_3 injection data had been obtained, the ammonia injectors were removed and the temperature probe was reinserted and again temperatures were recorded. The temperature during the ammonia injection test was then determined by interpolating between the temperatures recorded at the beginning and end of each test.

A series of preliminary tests were conducted to assess the potential problems that might occur when using the aspirated temperature probe to measure exit gas temperatures under coal fly ash conditions. Using the Utah coal it was found that plugging of the probe tip occurred after a few minutes of aspirated operation. The problem was so severe as to make it impractical, from fuel usage and time considerations, to attempt to fully calibrate the temperature probe when firing coal.

The basic calibration of the temperature probe was done while firing natural gas. The optimum aspiration rate on gas firing for the probe was used for all other tests where it was necessary to obtain "true" gas temperatures.

2.4.2 Test Matrix

The scope of the testing covered the following range of variables:

- primary fuel type
- ammonia concentration
- combustion gas temperature
- hydrogen concentration.

The actual range of the above variables which were investigated are presented in the test matrix outlined in Table 2.

TABLE 2. TEST MATRIX

a. Ammonia Injection Tests

Variable	Range	Fuel				
		Natural Gas	Utah Coal	Navaho Coal	Illinois Coal	Pittsburgh Coal
Excess Oxygen	Approx. 5%	1*	1	1	1	1
Nitric Oxide Level	Burner Produced (500-810 ppm)§	1	1	1	1	1
Temperature at Injection Point	1330 °F - 1965 °F	4	10	6	6	9
NH_3 Injection Rate	$NH_3/NO = 0 - 1.5$† molar	4	4	4	4	4
Approximate number of test conditions for each fuel		16	40	24	24	36
Approximate total number of ammonia injection tests	140					
b. Ammonia/Hydrogen Tests						
Excess Oxygen	Approx. 5%	--	--	--	--	1
NOx Level	Burner Produced (approx. 650 ppm)	--	--	--	--	1
Temperature at Injection Point	1300 °F - 1700 °F	--	--	--	--	4
NH_3 Injection Rate	$NH_3/NO \sim 1.0, 1.5$ molar	--	--	--	--	2
H_2 Injection Rate	$H_2/NO_0 = 0 - 2.5$	--	--	--	--	4
Approximate number of NH_3/H_2 Injection Tests		--	--	--	--	32

*Signifies approximate number of test conditions

§Limited testing done at ratios approaching 6

†For the natural gas tests, NO was added to the combustion air to produce a stack level of 500 ppm

SECTION 3.0

EXPERIMENTAL RESULTS

3.1 TEMPERATURE DISTRIBUTIONS

3.1.1 Axial Temperature Profiles

For each fuel type, an axial centerline temperature profile was established for determination of the proper location of the ammonia injectors for each test. A comparison of typical profiles for each fuel is given in Figure 6. In this figure, changes in the axial centerline temperature are plotted relative to the temperature two feet from the back wall. This was done to allow a more direct comparison for the fuels tested. The change in temperature with axial location is influenced by the firing rate, ash content of the coal, and number of heat shields used. A common curve for all fuels and all conditions would not be expected; however, the axial profiles are similar from coal to coal.

3.1.2 Radial Temperature Profiles

Radial temperatures were measured for all fuel types except the high ash Navaho coal. Two of the three coals showed flat radial temperature profiles with a total temperature variation of less than 200 °F. The natural gas fuel showed a radial temperature variation of approximately 250 °F. Typical radial variations are shown on Figure 7. The differences in the absolute temperatures in Figure 7 result from the fact that these data were obtained at various axial locations. The data shown for the Pittsburgh coal were obtained with the stainless steel liners removed in order to illustrate the range of radial temperature gradients experienced throughout the study.

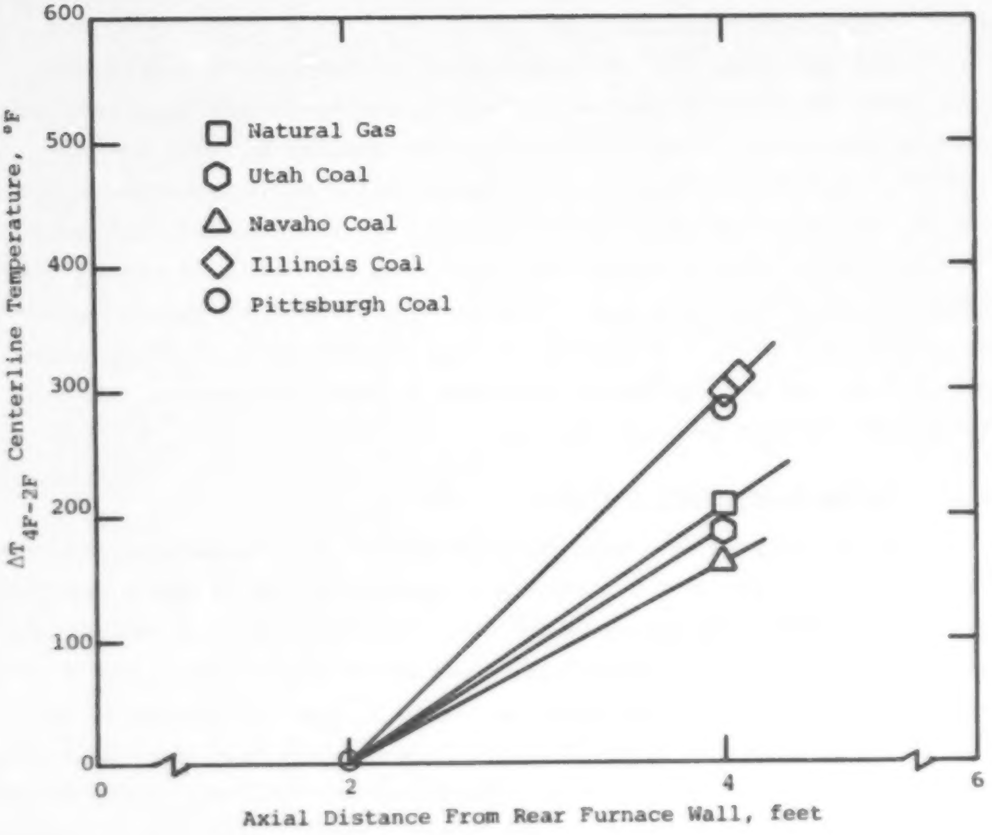


Figure 6. Typical axial variations of centerline temperature.

From Figure 7 it can be seen that the axial centerline temperature represents very nearly the average temperature for all of the coal types. However, for the natural gas fuel, the centerline temperature is approximately 100 °F higher than the average radial gas temperature.

In all of the following data presentation, the centerline gas temperature has been used as representative of the average radial temperature for the coal tests. For the natural gas tests, the average radial temperature is taken to be 100 °F lower than the measured centerline temperature.

The differences in the radial temperature profiles between natural gas and coal firing were attributed to the burners. The gas burner was fired at a lower air swirl setting than the coal burner to insure flame stability. As a result of the lower swirl, the gas burner flame was visibly longer and further from the walls than was that of the coal burner flame.

3.2 COAL PROPERTIES

The coals chosen for the test program were intended to cover a wide range of composition and to be representative of typical steam coals currently in use and of potential future use by the utilities.

All coals were procured in bulk form, air dried and then pulverized. Pulverized coal samples were obtained during the test program for each of the coals tested. An analysis of these coal samples is contained in Appendix D. A brief comparison of the primary coal properties is presented in Table 3.

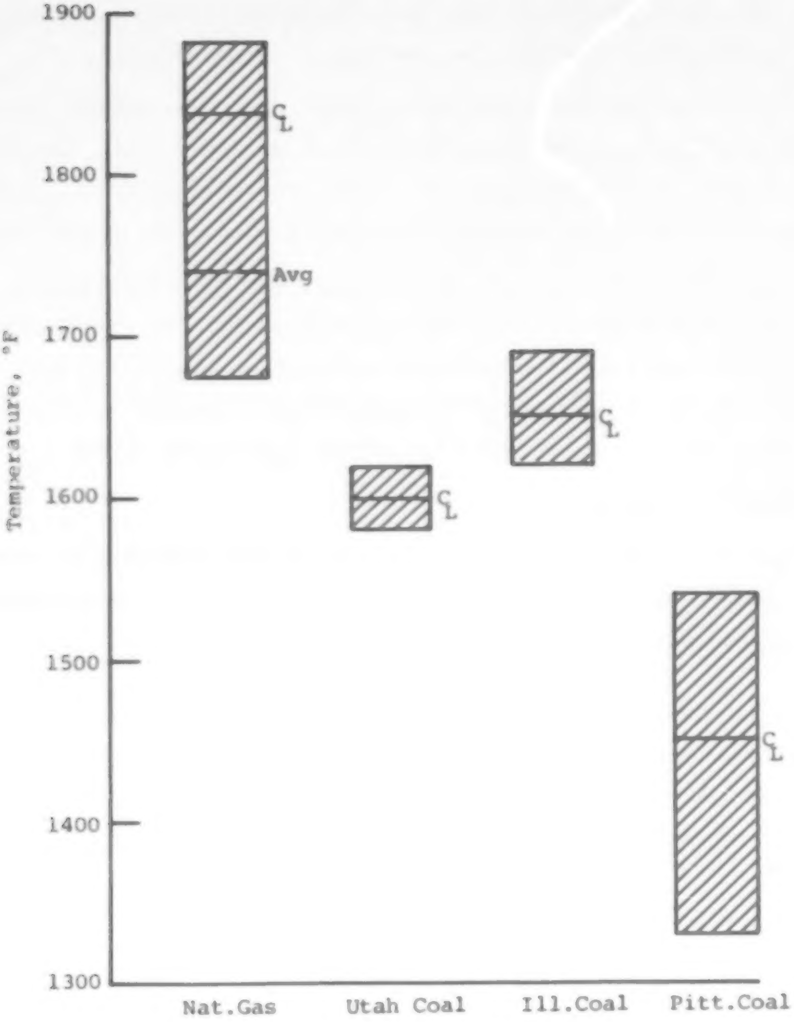


Figure 7. Typical radial temperature variations.

TABLE 3. COAL PROPERTIES (AS FIRED)

Rank	Utah Bituminous	Navaho Subbituminous	Illinois Bituminous	Pittsburgh Bituminous
Proximate Analysis				
% Moisture	4.24	8.33	12.02	1.67
% Ash	4.85	17.00	10.24	7.16
% Volatile	36.38	34.53	33.27	37.13
% Fixed Carbon	54.53	40.14	44.48	54.04
HHV (Btu/lb)	13111	10336	10941	13624
Ultimate Analysis (% wt)				
Moisture	4.24	8.33	12.01	1.67
Carbon	71.52	57.98	60.42	76.16
Hydrogen	5.44	4.40	4.36	5.10
Nitrogen	1.52	1.48	1.07	1.48
Chlorine	0.01	0.01	0.03	0.02
Sulfur	0.54	0.57	2.94	1.81
Oxygen	11.88	10.23	8.93	6.60
Sulfur Forms				
% Pyritic Sulfur	0.19	0.19	1.27	0.93
% Sulfate Sulfur	0.01	0.00	0.06	0.02
% Organic Sulfur	0.34	0.38	1.61	0.86
Total Sulfur	0.54	0.57	2.94	1.81

Ash content varied from 4.85% for the Utah coal to 17% for the Navaho subbituminous. The sulfur levels covered a wide range from 0.54% for the Utah coal to 2.94% for the Illinios coal. The fuel nitrogen did not vary greatly from one coal to another.

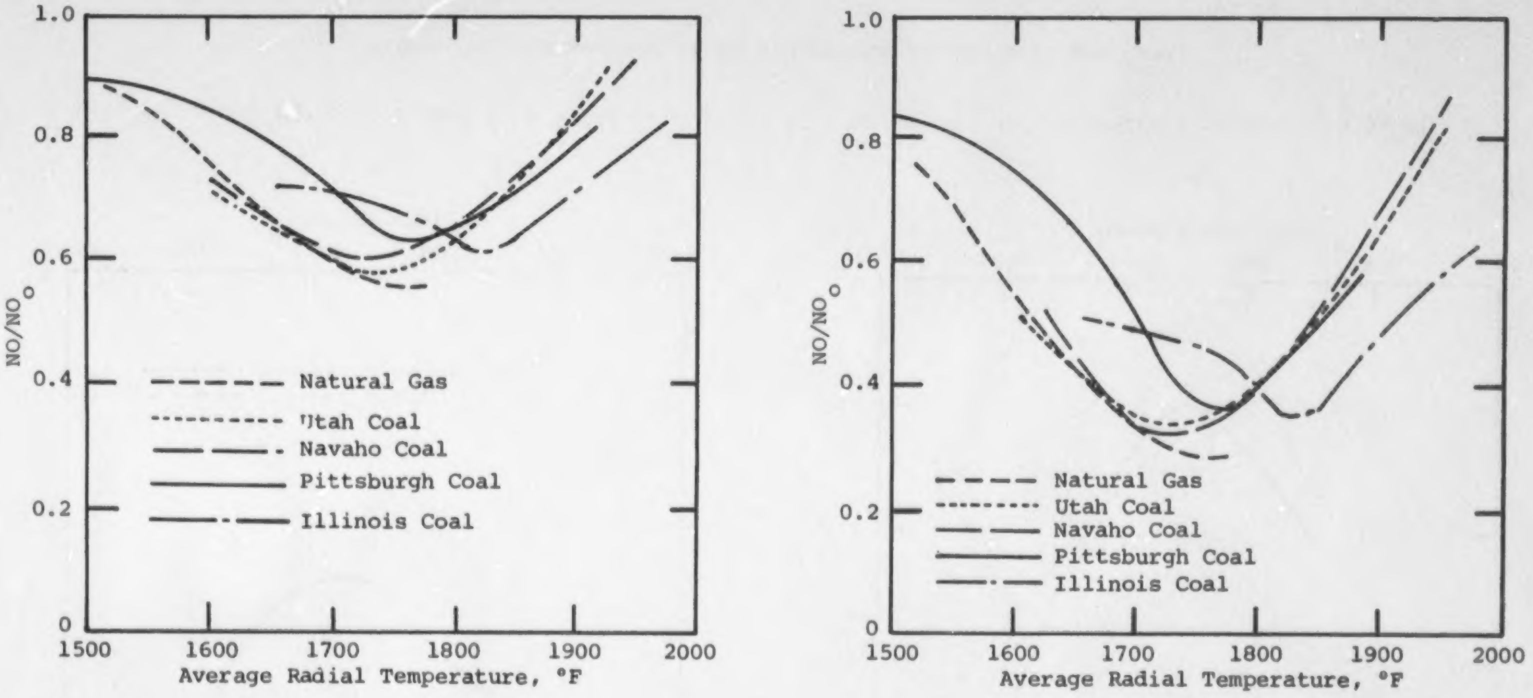
3.3 NITRIC OXIDE REDUCTIONS

3.3.1 Effect of Temperature and Coal Type

One of the primary variables which determines the amount of NOx removed by the injected ammonia is temperature. Previous studies have shown that the selective homogenous gas-phase reduction of nitric oxide occurs optimally at about 1750 °F in gas and oil-fired systems. One of the major objectives of this study was to determine if comparable results would be obtained with coal-fired systems and the extent to which varying coal properties (e.g., sulfur content, ash characteristics, etc.) might affect the efficiency of the process. A summary of the results obtained during this study for all four coals and natural gas is shown in Figures 8a and 8b at molar ratios of ammonia to initial nitric oxide of 0.5 to 1.0 respectively. It should be noted that the curves shown in Figures 8a and 8b are cross plots of the data, and not curves drawn directly through the data points.

For comparison, the data from Reference 4 are shown relative to the natural gas tests obtained during this program in Figure 9. The data from Reference 4 represent NO reductions by ammonia in a natural gas-fired combustion tunnel which was isothermal radially and provided rapid mixing of the ammonia with the combustion products. The NO reductions obtained with coal and gas firing during this study were not as great as those previously obtained in the small combustion tunnel (Ref. 4). This is probably attributable to the radial temperature gradients in the larger coal and gas fired combustion tunnel.

The other point to be noted is that while the temperature required for peak NO reductions fell within the range of 1720 °F and 1830 °F, the range for natural gas and the Utah, Navajo, and Pittsburg coals was between 1720 °F and 1760 °F. The temperature required for peak NO reduction on Illinois coal was approximately 1830 °F. The levels of NO reduction on all fuels tested were comparable.



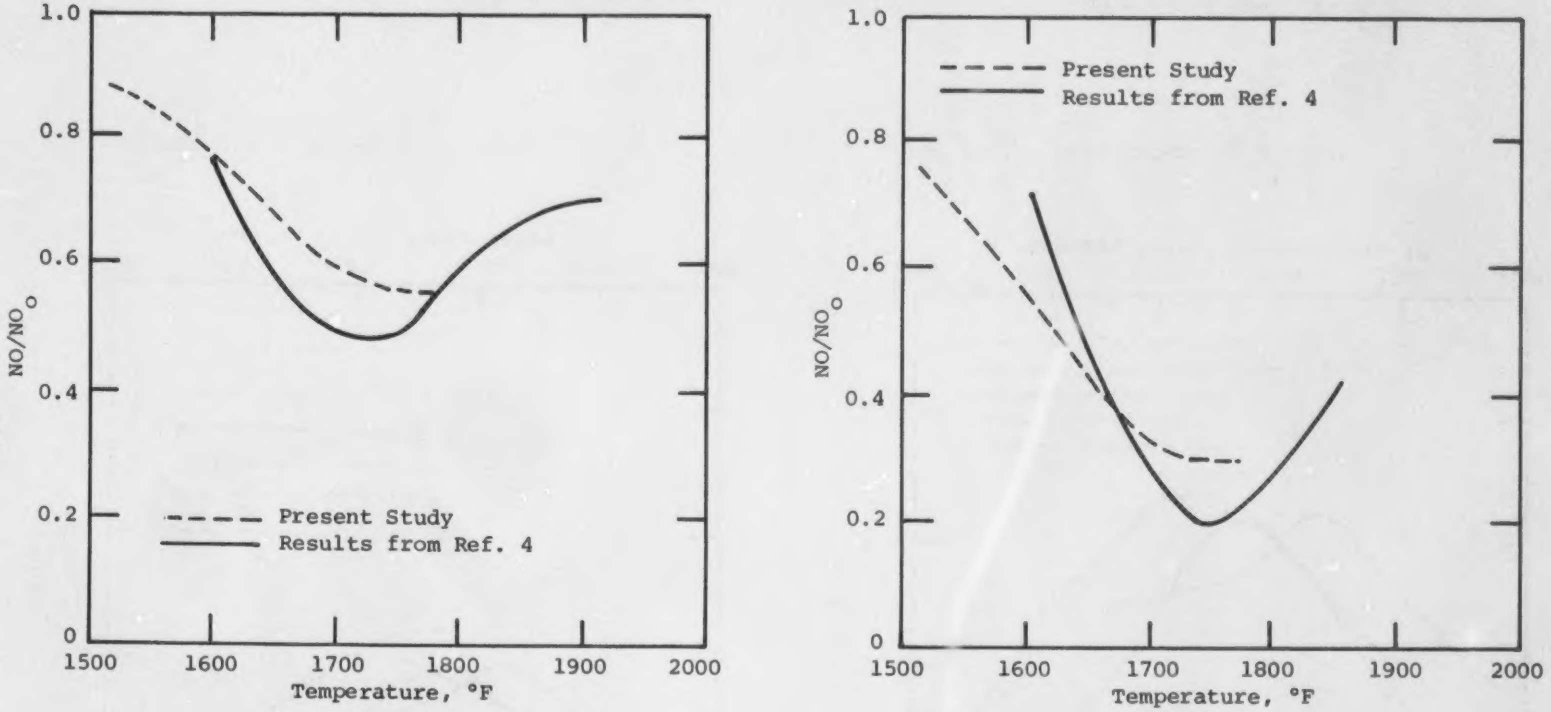
A.

(NH_3/NO_o = 0.5, Excess O_2 ∿ 5.0%)

B.

(NH_3/NO_o = 1.0, Excess O_2 ∿ 5.0%)

Figure 8. Effect of temperature on NO reductions, coal and natural gas firing.



A.

[NH_3/NO_o = 0.5 (molar), Excess O_2 ∿ 5.0%]

B.

[NH_3/NO_o = 1.0 (molar), Excess O_2 ∿ 5.0%]

Figure 9. Comparison of NO reductions for natural gas fuel.

One possible reason for the variation of temperature required for peak reduction might be the sulfur content of the fuel. Limited testing was conducted to determine the possible effect of sulfur on the NO reduction process. During these tests, the unit was fired with a distillate type oil. Carbon disulfide (CS_2) was used to vary the sulfur content of the flue gases. Ammonia was then injected at molar ratios of NH_3 to initial NO of 1.0, and the injectors moved axially in the furnace to change the average temperature at the point of injection. The results of these tests are shown in Figure 10 for sulfur dioxide levels in the combustion products ranging from 120 to 2900 ppm. Over the range of sulfur tested, there was no effect in terms of the temperature at which maximum NO reductions were achieved. In Figure 10 the data have been plotted as a function of axial location at the point of NH_3 injection along with a scale showing the approximate average axial temperature. This was done since the radial temperature gradients with oil firing are greater than with coal, and sufficient characterization was not made in order to establish an accurate average radial temperature. While these tests do not conclusively eliminate sulfur as having an effect on the NO reduction process, they suggest very strongly that the sulfur does not interfere with the NO/NH_3 chemistry.

3.3.2 Effect of Ammonia Injection Rate

The effect of the amount of ammonia injected on the NO reductions is shown in Figures 11 through 15 for the four coals and natural gas. In these figures, the ratio of the final NO concentration to initial NO concentration is plotted versus the ratio of the amount of ammonia injected to the initial concentration of NO (molar basis). Two test series are shown in these figures. The open symbols represent tests for which ammonia, cyanide, and nitrate data were obtained. The closed symbols represent results of tests in which only the reductions in NO were determined to establish repeatability.

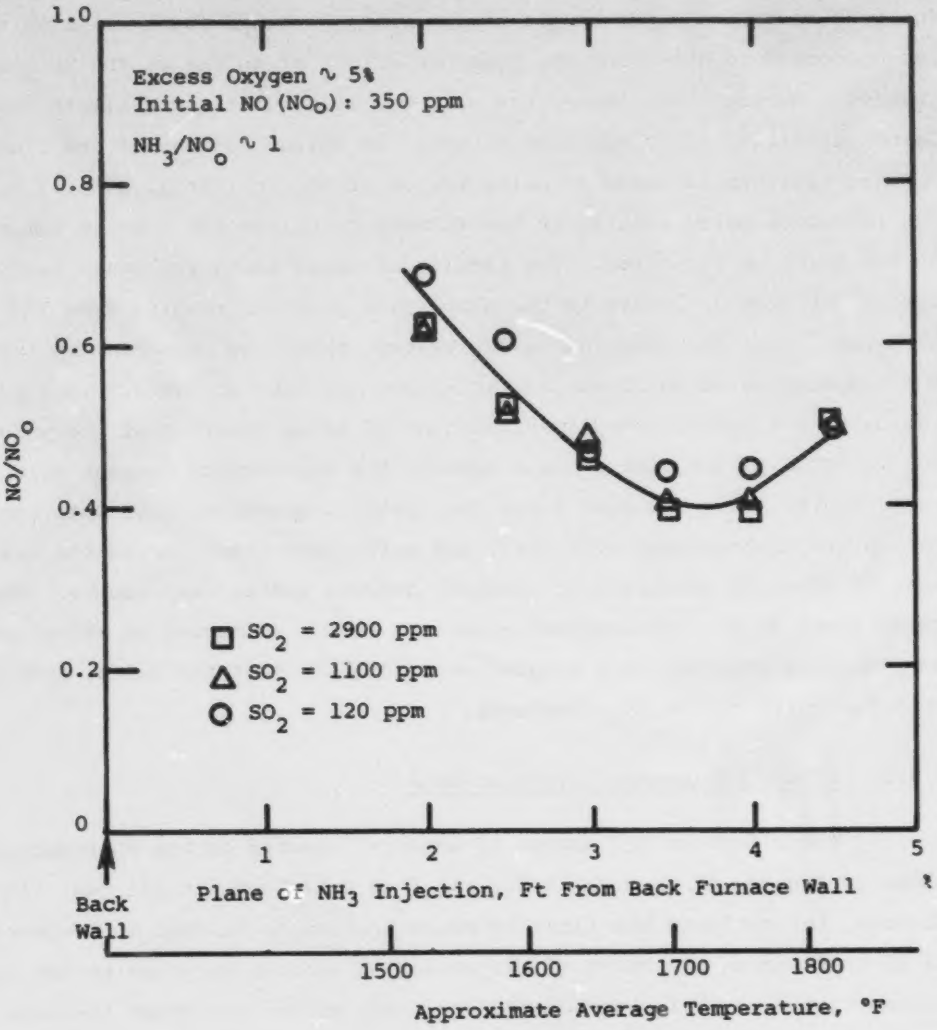


Figure 10. Effect of sulfur on NO reduction (oil firing.)

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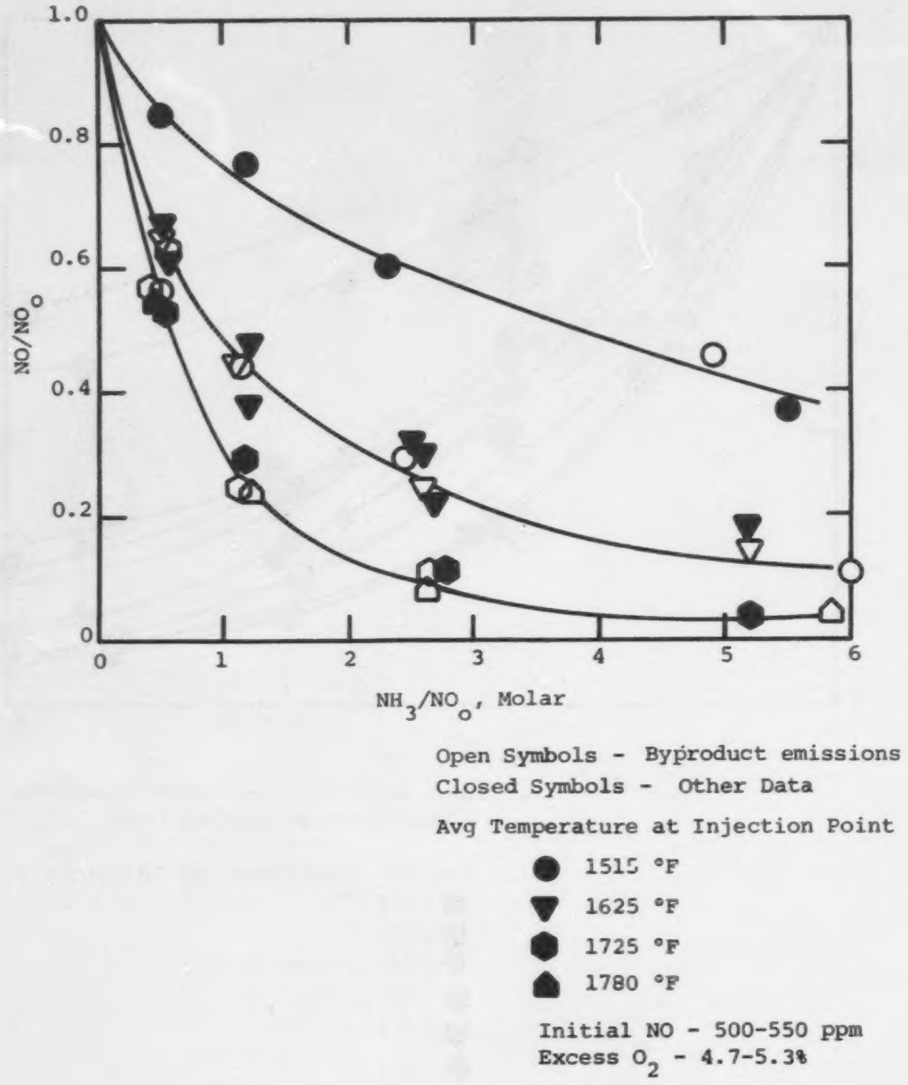


Figure 11. Effect of NH$_3$ injection rate on NO reductions (natural gas fuel).

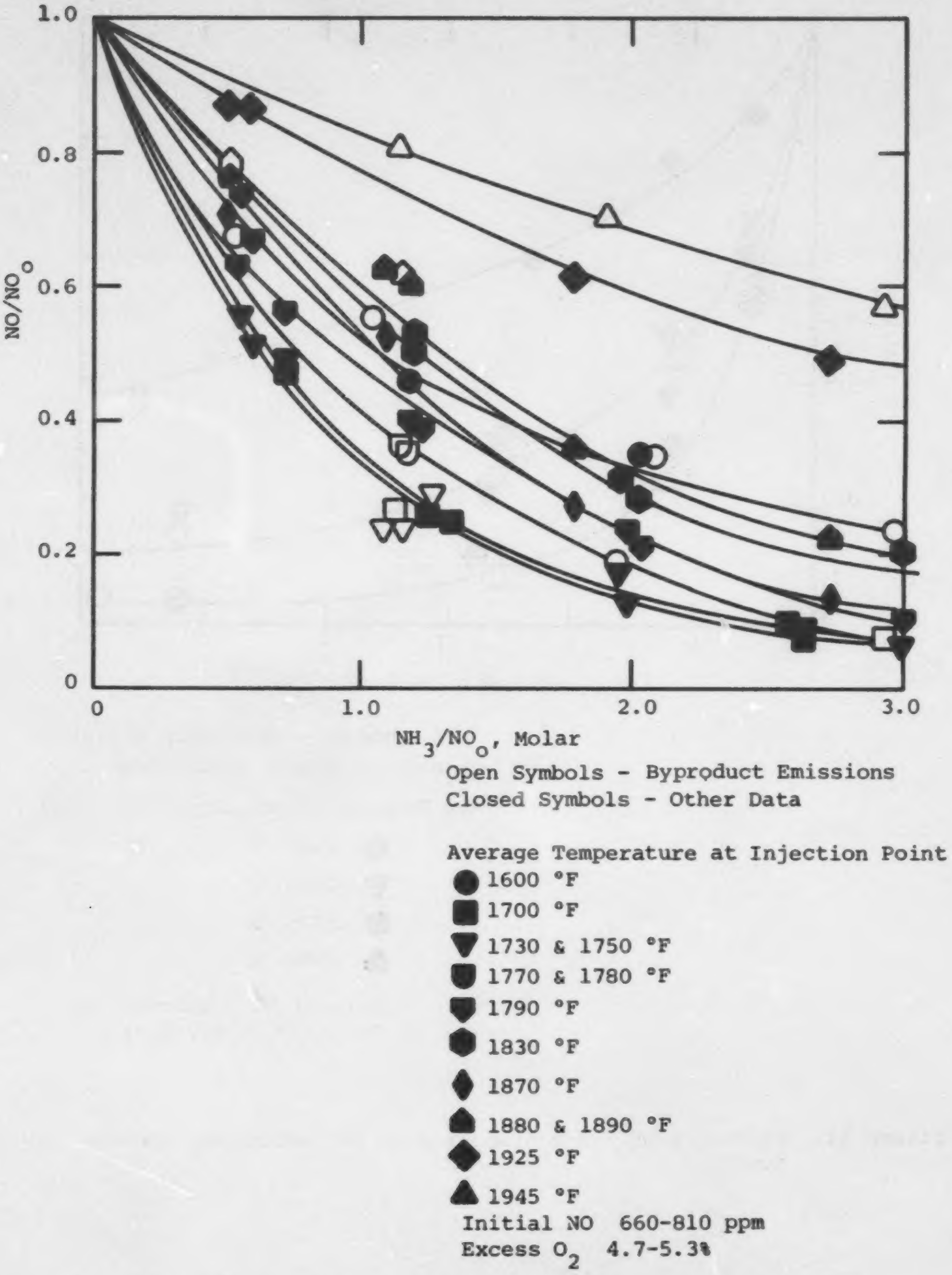


Figure 12. Effect of NH_3 injection rate on NO reductions (Utah coal).

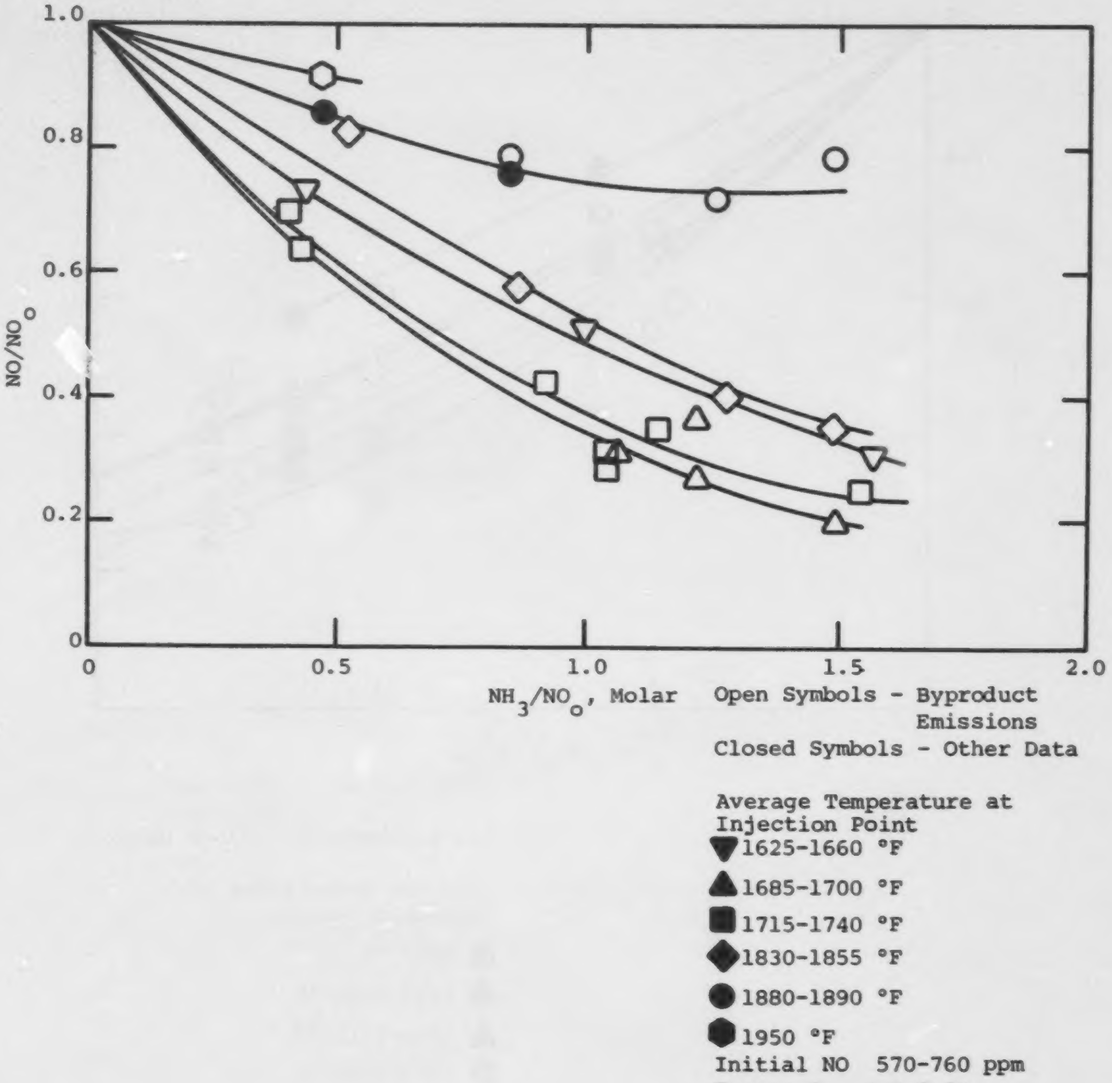


Figure 13. Effect of NH$_3$ injection rate on NO reductions (Navaho coal).

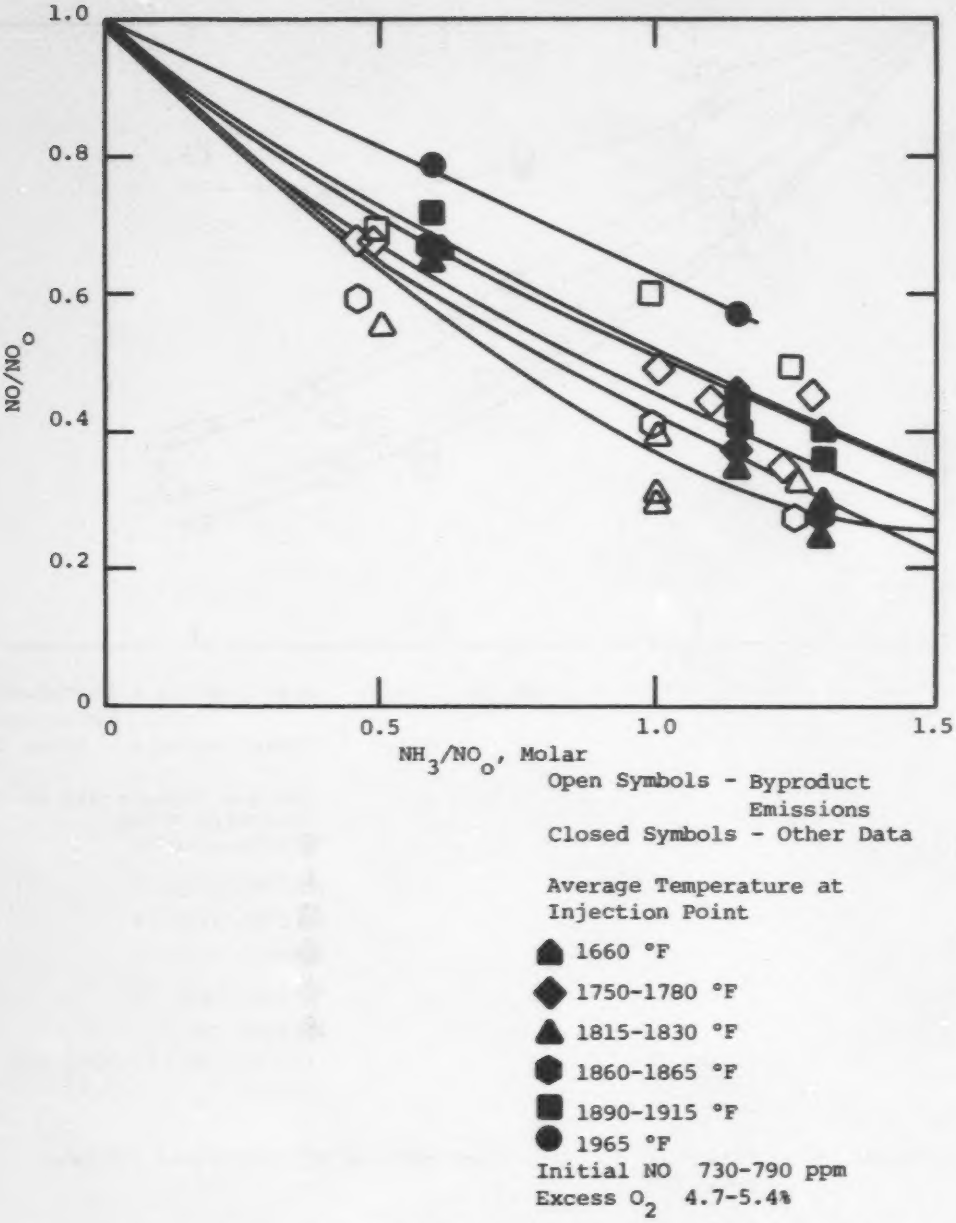


Figure 14. Effect of NH$_3$ injection rate on NO reductions (Illinois coal).

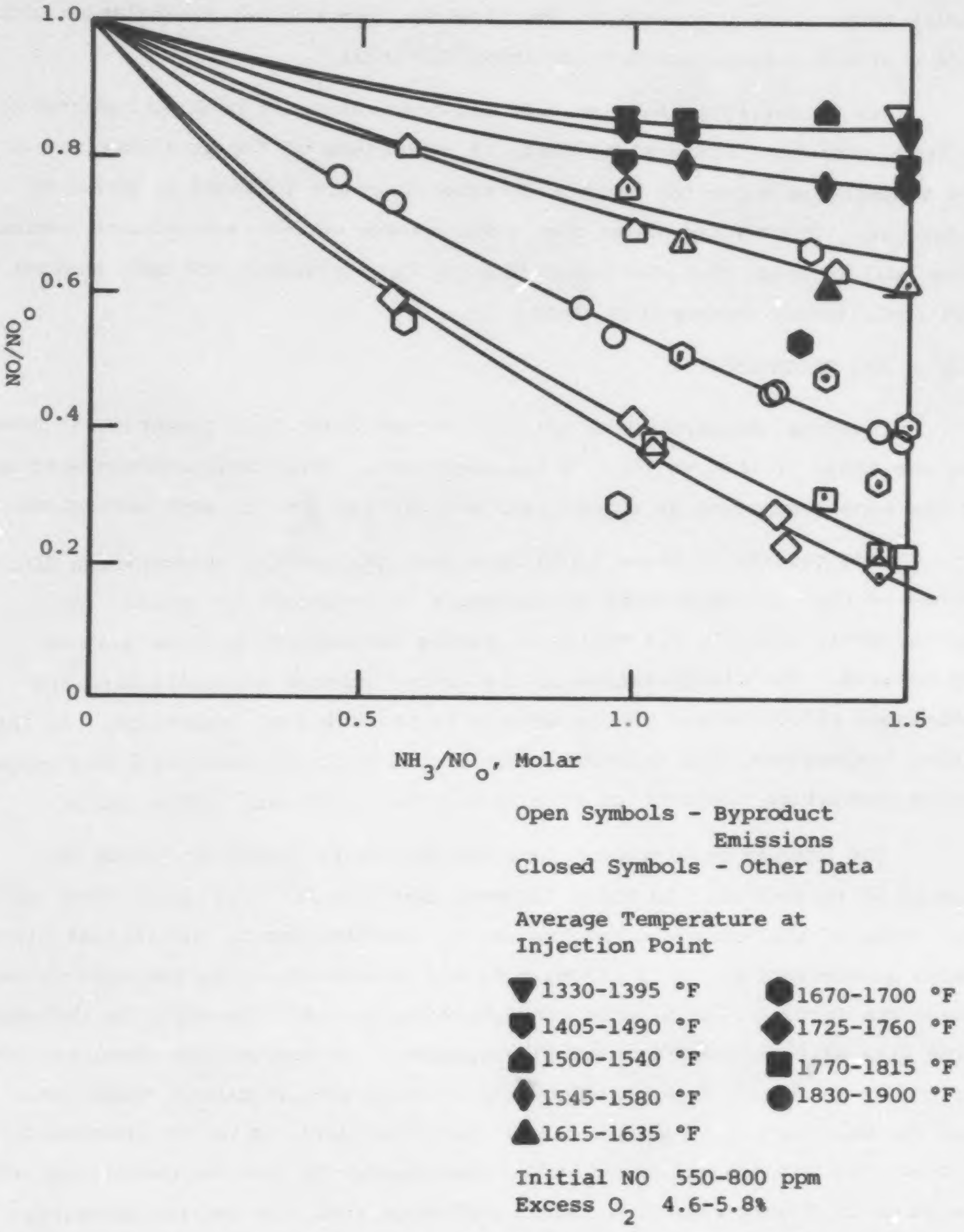


Figure 15. Effect of NH$_3$ injection rate on NO reduction (Pittsburgh coal).

Scatter in the data is suspected to be primarily due to variations in the radial temperature gradients in the firetube, and the ash accumulation which made a single temperature determination difficult.

As discussed in Section 3.2, the temperature at peak NO reductions differed somewhat from fuel to fuel. A comparison of the data obtained at the temperature where the maximum NO reductions are achieved is shown in Figure 16. This figure shows that although the optimum temperature varied from coal to coal, the peak reductions in NO were within the data scatter for all fuels tested during this study.

3.4 NH_3 EMISSIONS

Ammonia emissions were measured for at least four temperatures covering the range of 1600 to 2000 °F for each coal. These measurements were made at the same conditions at which cyano and nitrate species were determined.

The results of these tests show that the ammonia breakthrough diminishes as the gas temperature at the point of injection increases. At approximately 1900 °F, all traces of excess ammonia in the flue gas had disappeared. The disappearance of the excess ammonia coincides with the diminished effectiveness of the ammonia in producing NO reductions. At the higher temperature, the injected ammonia will begin to react with the oxygen in the combustion products to form rather than eliminate nitric oxide.

The ammonia breakthrough data for all fuels tested are shown in Figure 17 through 21. In these figures, the data are plotted in terms of the ratio of the ammonia concentration in the flue gas to the initial nitric oxide concentration. This allows a direct comparison among the various tests where the initial nitric oxide concentration varied. The scale on the right-hand side of Figures 17 through 21 represents the approximate absolute level of NH_3 in the stack gases based on the average initial nitric oxide level for the test series. As with the NO reduction data, it is of interest to compare the ammonia emissions at the temperature of peak NO reductions; this is shown in Figure 22. This figure indicates that the ammonia emissions, when normalized to the initial NO concentrations, were comparable except for the Illinois coal tests. The NH_3 emissions from the Illinois coal tests were significantly lower throughout the range of ammonia injection rates tested.

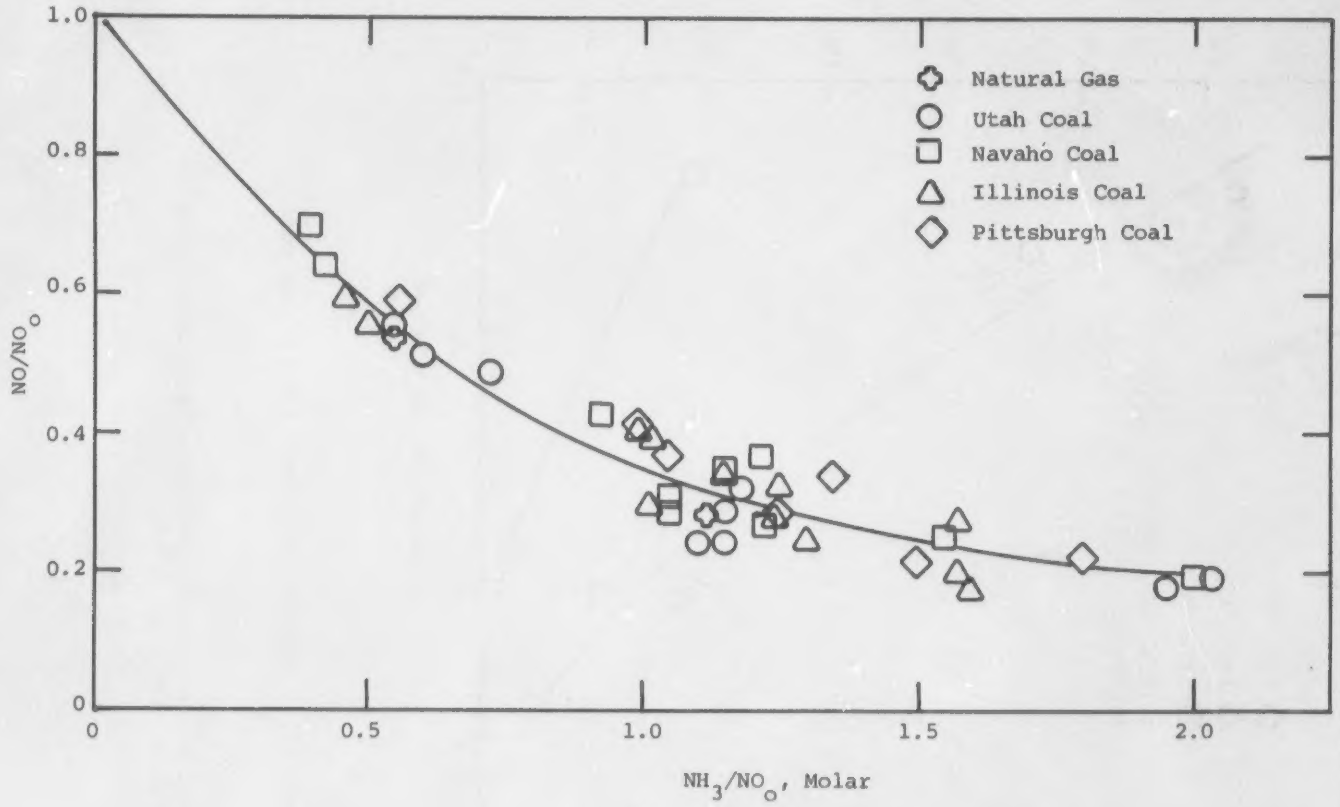


Figure 16. Comparison of NO reductions at the optimum temperature condition.

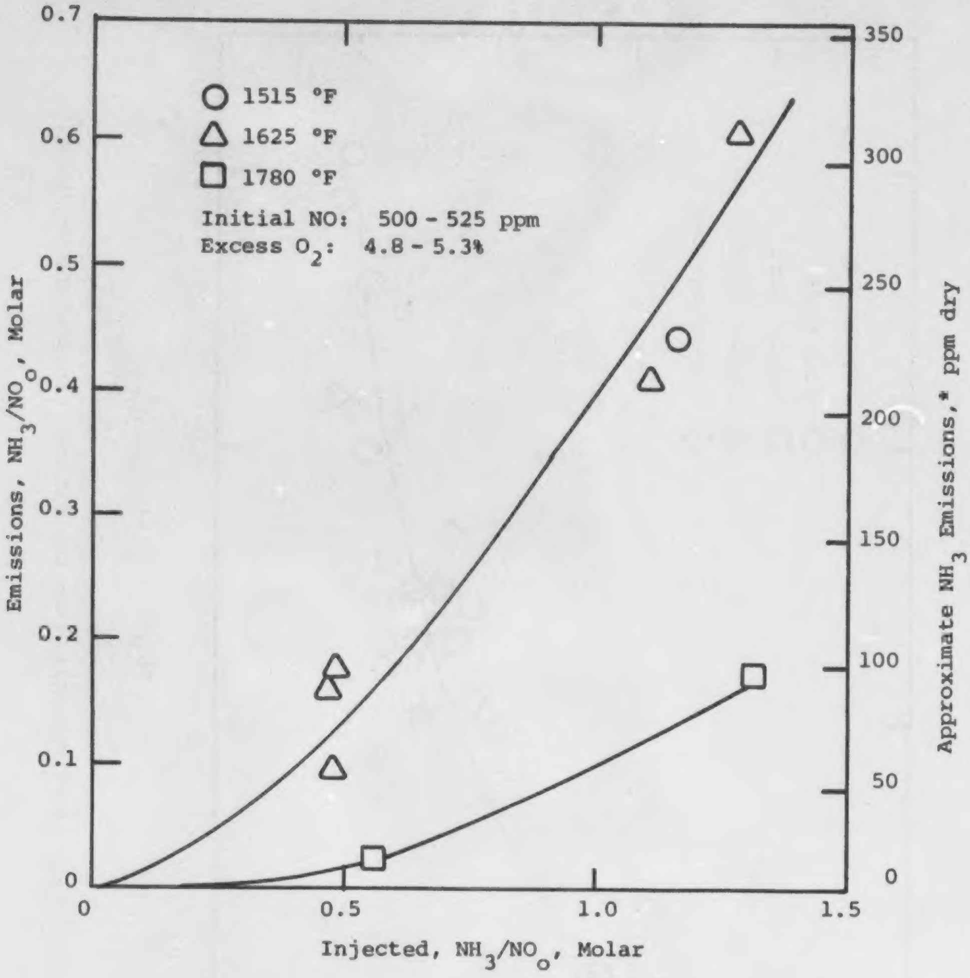


Figure 17. Ammonia emissions, natural gas fuel.

*Based on the average initial nitric oxide level level for the test series.

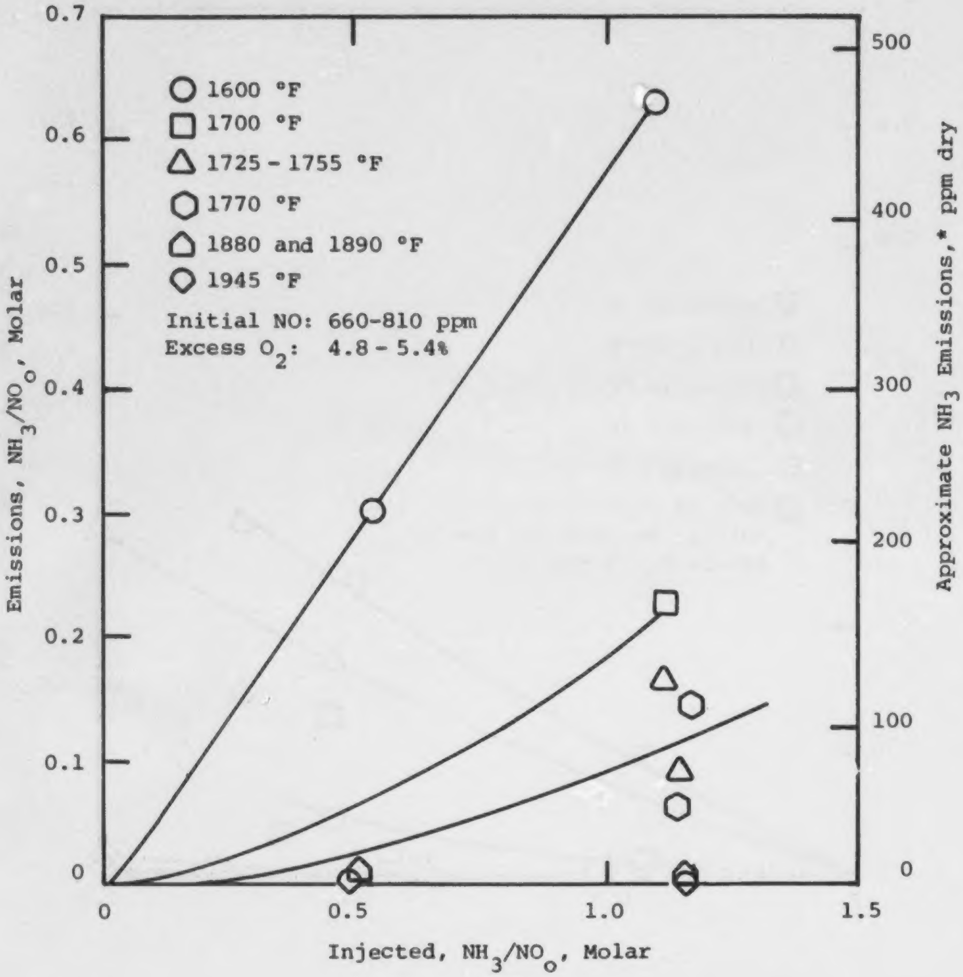


Figure 18. Ammonia emissions, Utah coal.

*Based on the average initial nitric oxide level for the test series.

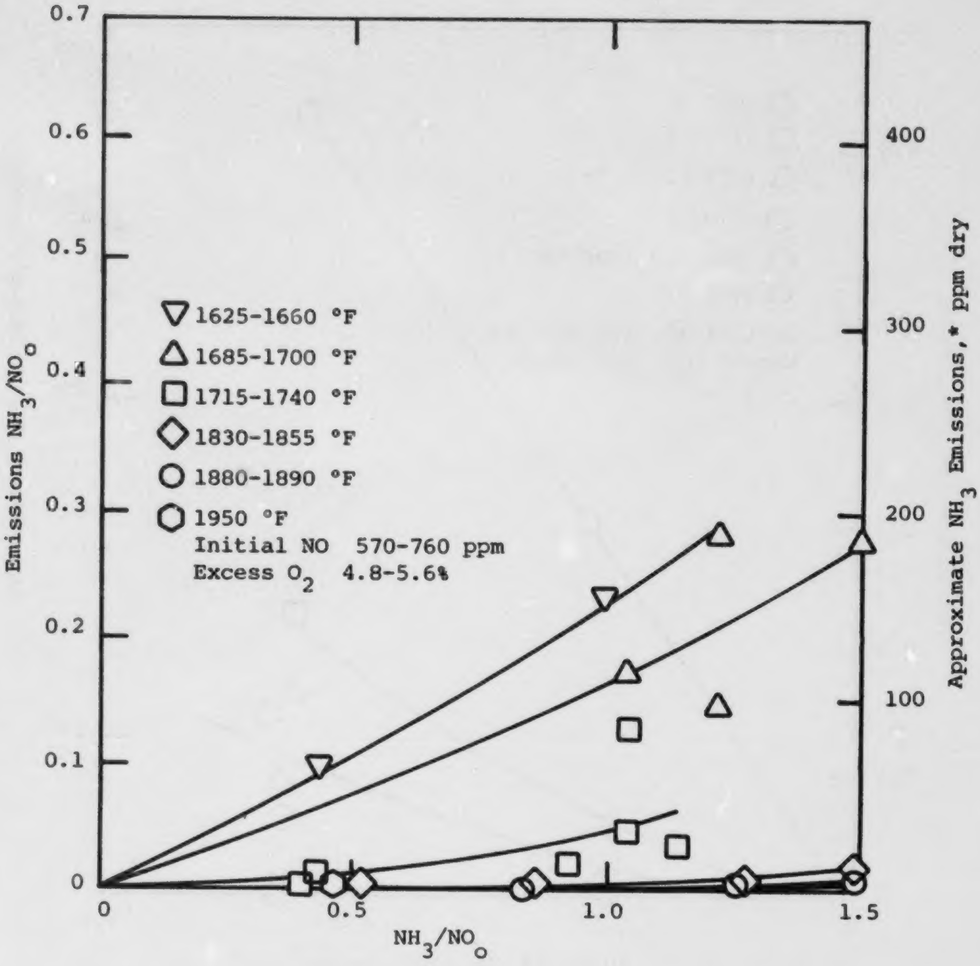


Figure 19. Ammonia emissions, Navaho coal.

*Based on the average initial nitric oxide level for the test series.

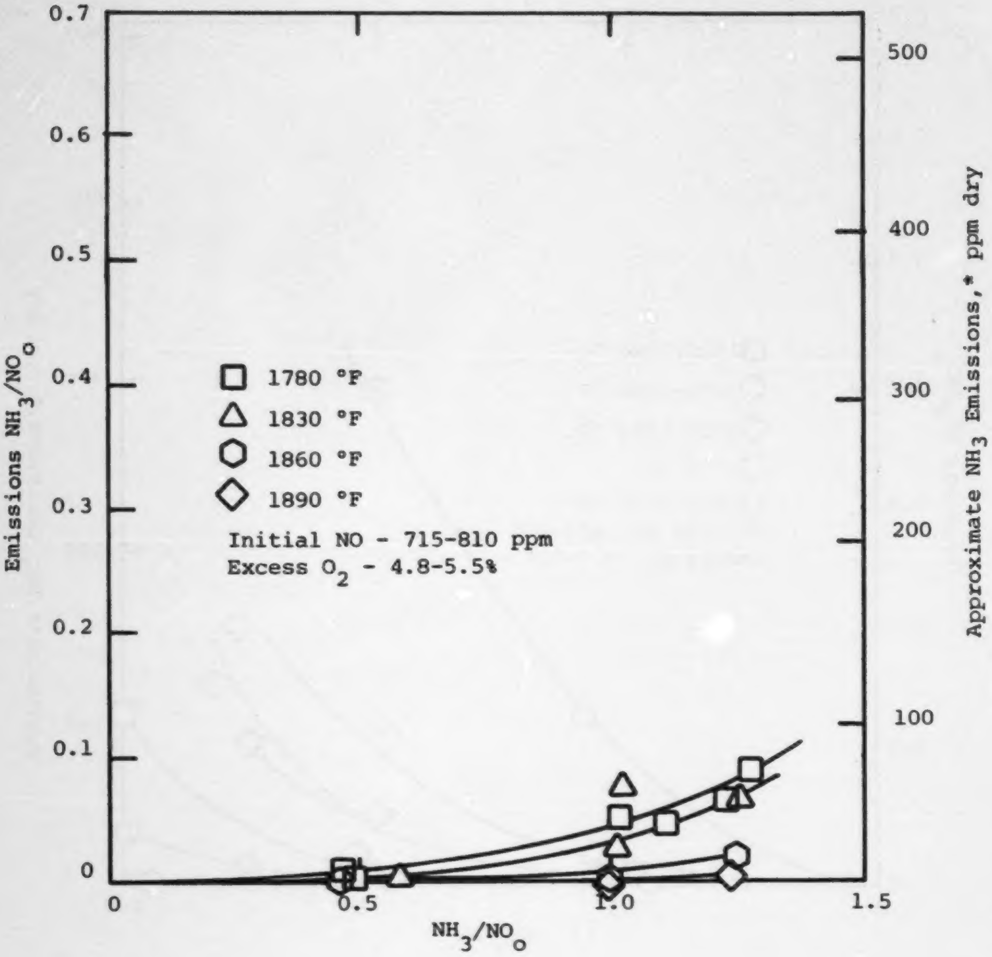


Figure 20. Ammonia emissions, Illinois coal.

*Based on the average initial nitric oxide level for the test series.

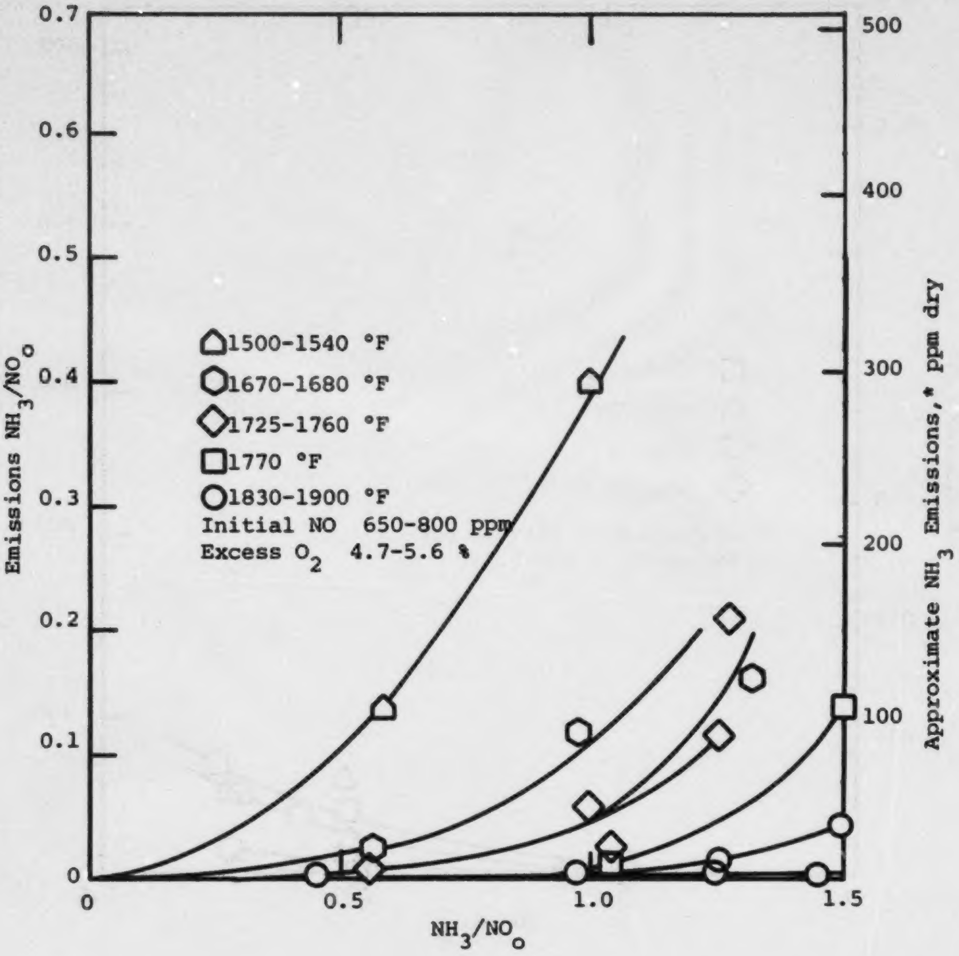


Figure 21. Ammonia emissions, Pittsburgh coal.

*Based on the average nitric oxide level for the test series.

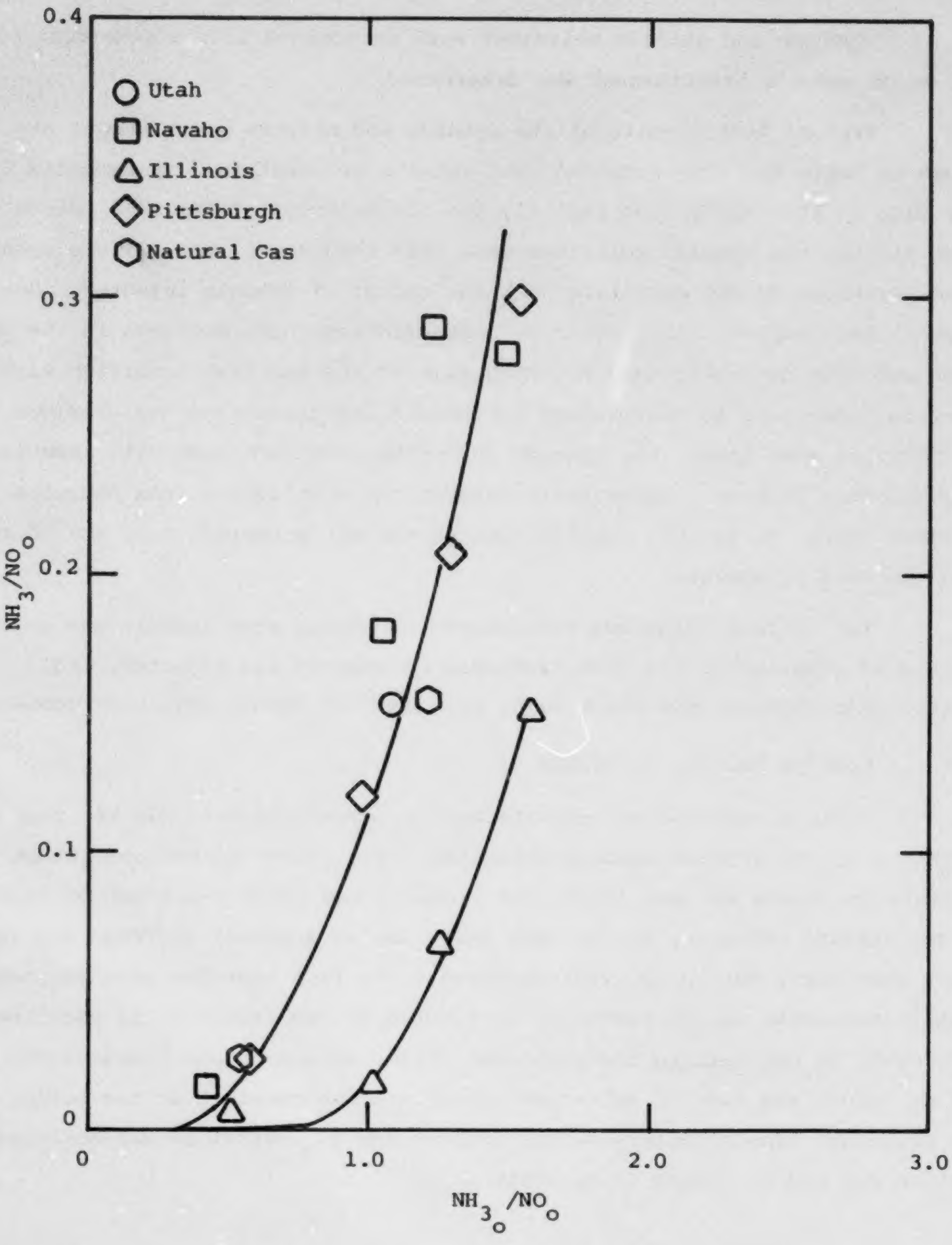


Figure 22. Comparison of the NH_3 emissions for all fuels tested at the peak NO removal temperature.

3.5 CYANIDE AND NITRATE EMISSIONS

Cyanide and nitrate emissions were determined at the same test points at which ammonia breakthrough was determined.

Typical test results of the cyanide and nitrate measurements are shown in Table 4. (The complete test results are contained in Appendix C.) The data in this table show that (1) for the majority of the data points with coal firing, the cyanide emissions were less than 2 ppm, and (2) the cyanide concentrations do not correlate with the amount of ammonia injected. During several test series, higher cyanide concentrations were measured in the combustion products but again this occurred also at the baseline condition with no ammonia injection; no correlation to ammonia injection rate was observed. In fact, in some cases, the cyanide concentrations were less with ammonia injection than without. These tests support the conclusions from previous studies (Refs. 3, 4) that cyanide species are not a byproduct of the NO reduction process by ammonia.

The nitrate emissions also showed no change when ammonia was injected as compared to the condition when no ammonia was injected, indicating that nitrates are not a major byproduct of the NO reduction process.

3.6 SULFATE AND SO_3 EMISSIONS

Table 5 contains the sulfate and SO_3 emissions data for the four coals tested with and without ammonia injection. The effect of the ammonia on the sulfate emissions was not conclusive since in two cases there was no change in the sulfate emission; in one case there was an apparent increase and in the other case there was an apparent decrease. The fact that the data are somewhat inconclusive can be partially attributed to two factors: (1) experimental difficulty in maintaining the probe and filter at a constant temperature, and (2) no effort was made to determine if sulfate was retained in the boiler. The procedure used to determine the sulfate and SO_3 emissions was outlined in Section 2.3 and discussed in Appendix B.

TABLE 4. SUMMARY OF CYANIDE AND NITRATE CONCENTRATIONS

	Ammonia Inj. Condition		Flue Gas Composition		
Fuel	T_{Avg} (°F)	NH_3/NO_o Molar	NO/NO_o	CN ppm	NO_3^- ppm
Natural Gas	--	0	1.0	<1	0.4-0.9
	1780	0.55	0.53	<1	--
	1780	1.23	0.24	<1	--
	1725	1.21	0.29	<1	--
	1620	2.5	0.3	<1	1
Utah Coal	--	0	1.0	<1→8	<1
	1700	1.14	0.27	2	<1
	1770	3	0.07	3	<1
Navaho Coal	--	0	1.0	0-2	6-8
	1700	1.04	0.31	<1	8
	1740	1.14	0.35	<1	6
	1840	1.28	0.41	<1	6
	1880	1.5	0.79	<1	8
Pittsburgh Coal	--	0	1.0	<1→7	8-22
	1730	0.6	0.59	3	6
	1750	1.0	0.41	1	11
	1760	1.26	0.27	6	11
	1770	1.5	0.21	7	12
	1850	1.0	0.54	10	6
	1870	1.5	0.38	3	9
Illinois Coal	--	0	1.0	<1→4	13-14
	1830	0.5	0.55	7	13
	1830	1.0	0.39	3	13
	1830	1.3	0.32	<1	13
	1830	1.6	0.27	<1	16
	1860	1.0	0.41	3	12
	1860	1.25	0.27	2	13
	1860	1.57	0.20	1	12

TABLE 5. SULFATE AND SO_3 EMISSIONS WITH AND WITHOUT AMMONIA IN THE FLUE GAS

Coal	ppm, uncorrected NH_3	SO_4	SO_3
Utah	0	5	1
	77	5	1
	108	4	1
Navaho	0	7	5
	32	7	3
Illinois	0	20	21
	22	26	18
Pittsburgh	0	32	19
	18	31	10

However, the SO_3 emissions were observed to decrease when ammonia was injected into the boiler for each coal tested and suggests that reactions between NH_3 and SO_3 are occurring. The decrease, however, was not in proportion to the amount of excess ammonia present in the flue gas.

Within the accuracy of the experimental measurements, it was not possible to detect a significant change in neutral sulfate emissions, although a slight reduction in SO_3 emissions with ammonia injection was observed. Further work to clarify this matter would seem warranted.

3.7 CARBON MONOXIDE EMISSIONS

The emissions of carbon monoxide from coal fired utility boilers while not of primary concern from the standpoint of pollution can have an impact on the efficiency of the unit. R. K. Lyon of Exxon Research and Engineering has indicated that the selective NO reduction process will inhibit the oxidation of CO to CO_2. Thus if CO is still present at the point of ammonia injection its oxidation could be prevented and it could be emitted to the atmosphere.

The test results from the present program on coal fired systems indicate that while there does appear to be some inhibition of the oxidation of CO to CO_2 this is not a problem over the range of ammonia concentrations of interest. Typical baseline CO emissions for the four coals tested are shown in Table 6 along with the CO levels over a range of ammonia injection rates at various temperature rates. As can be seen from the results of these tests, incremental emissions of CO with ammonia injection are slight and should not be a problem in coal-fired systems (further data can be found in the data summary sheets in Appendix C).

3.8 SO_2 AND NOx MEASUREMENTS

During the test program both SO_2 and NOx were measured to determine (1) if any excess ammonia reacted with the SO_2 and (2) if there was a change in the NO/NOx ratio (e.g. did the ammonia selectively react with NO or both NO and NO_2). For the case of the Utah and Navaho coals the NOx to NO ratio did not change upon the addition of ammonia indicating that the total oxides of nitrogen were reduced during the process.

Some difficulty was experienced in measuring the NO and NOx through the heated line under conditions where the flue gas contained high concentrations of NH_3 and SO_2; in particular for the tests with the Illinois and Pittsburgh coal. Reactions occurred in the heated sample line which resulted in a net loss of NOx. For instance, the dew point of the combustion products from the Illinois coal was on the order of 270 °F. Unfortunately the heated sampling line was only capable of operation to 260 °F. Thus some condensation was expected with subsequent reaction with the ammonia and NOx in the sample. Ideally it would be desirable to operate the sampling line above the dew point and temperature at which the ammonia/sulfur compounds form (i.e., approximately 320 °F).

TABLE 6. EFFECT OF AMMONIA INJECTION ON CO EMISSIONS

	Ammonia Injection Condition		Flue Gas Composition		
Fuel	T °F	NH_3/NO_o	NO/NO_o	NH_3 ppm	CO ppm
Utah	--	0	1.0	0	55
	1770	1.17	0.36	108	65
	--	0	1.0	0	60
	1770	1.14	0.21	178	85
	1700	2.93	0.08	1008	90
Navaho	--	0	1.0	--	75
	1715	0.4	0.7	32	75
	1725	0.92	0.43	13	75
	1740	1.14	0.35	22	65
	--		1.0	--	50
	1735	1.04	0.31	--	70
Illinois	--	0	1.0	--	50
	1830	0.51	0.55	3	50
	1830	1.02	0.39	12	50
	1830	1.57	0.27	112	50
Pittsburgh	--	0	1	--	50
	1730	0.56	0.59	5	80
	1750	1.0	0.41	41	100
	1770	1.5	0.21	100	100

A similar situation was encountered with the continuous measurement of SO_2. When the ammonia content of the sampled combustion products was on the order of a third of the SO_2 concentration a loss of SO_2 was observed in the sampling lines. This was a sampling line phenomena and not occurring in the boiler since when the ammonia was turned off the heated line took approximately 20 to 30 minutes to stabilize. This suggests an adsorption-desorption process on the teflon sampling line rather than a process occurring in the boiler. At lower SO_2 to NH_3 ratios in the flue gases there appeared to be no significant change in the SO_2 levels with ammonia injection. The observed changes were as much associated with sulfur variability in the coal fed to the boiler as any reaction with the excess ammonia. The sulfate and SO_3 measurements tend to support this observation.

3.9 AMMONIA AND HYDROGEN INJECTION

A limited number of tests were conducted to determine the effect of combined ammonia and hydrogen injection upon the NO reductions in coal-derived combustion products. The Pittsburgh seam #8 coal was used for these experiments.

Exxon studies with oil and gas fuels had shown that at a given temperature, hydrogen had the effect of increasing the NO reduction and simultaneously reducing the ammonia breakthrough. That is, the hydrogen can be used to produce higher nitric oxide reductions at lower temperatures.

The data collected during this study confirms that the hydrogen allows the reduction of NO with ammonia to occur at a lower temperature. A typical representation of the NO reduction effect is shown on Figure 23. It can be seen from this figure that the addition of hydrogen is beneficial in the low temperature range.

When the data such as that shown in Figure 23 are cross plotted against the amount of hydrogen injected (H_2/NH_3 molar ratio) for a given temperature, the resulting curve will exhibit a minimum (or maximum in terms of NO removal).

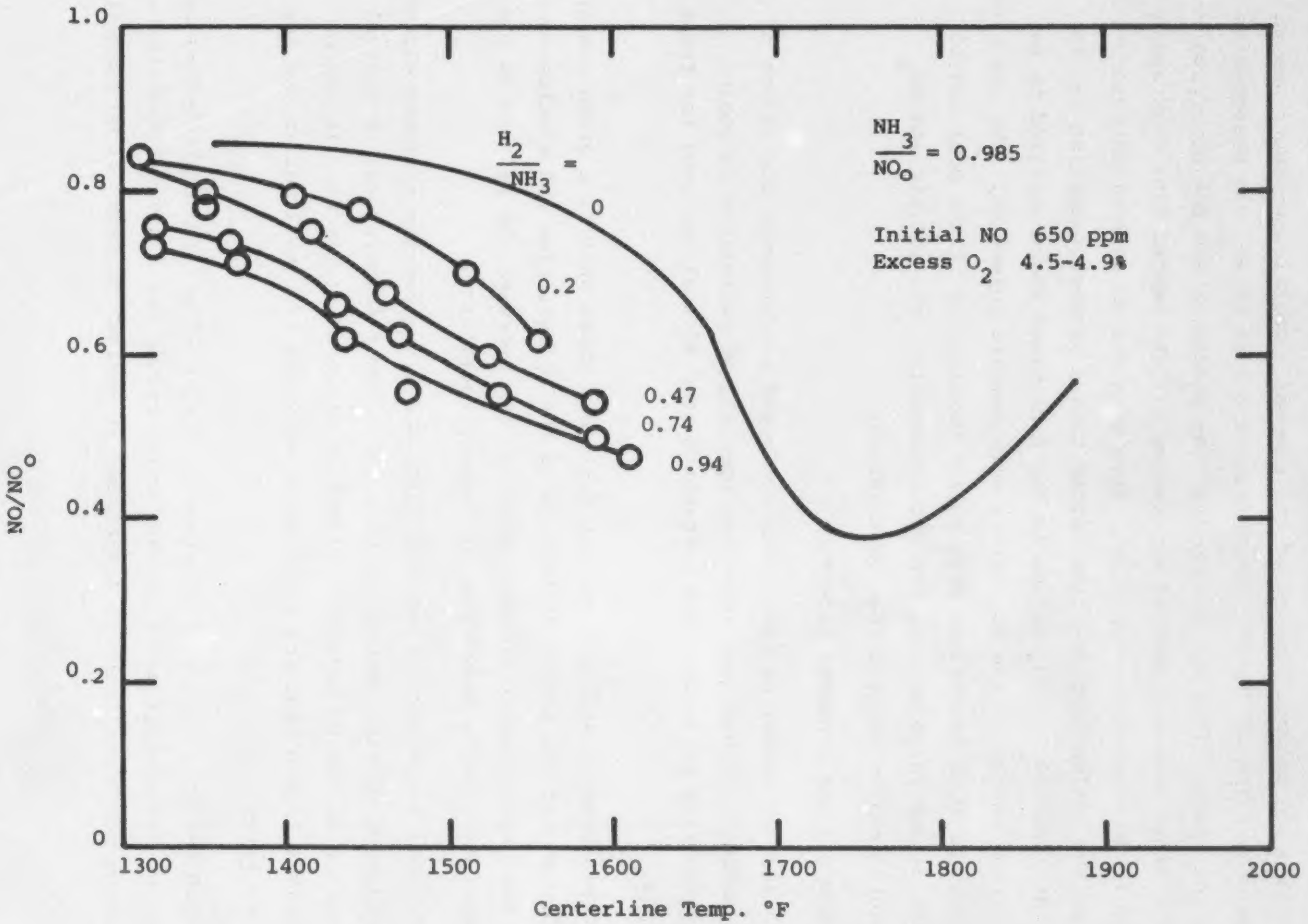


Figure 23. typical NO reduction with ammonia and hydrogen injection - Pittsburgh coal.

The locus of all maximum NO reductions plotted versus temperature are then plotted in Figure 24. This shows the maximum NO reductions achievable over the temperature range for a given amount of injected ammonia. Figure 24 clearly shows that at temperatures below the optimum, the NO reductions can be significantly better with H_2/NH_3 injection than with ammonia alone.

The ammonia emissions were measured for three temperature levels with H_2/NH_3 injection. The corresponding NO and NH_3 data are shown in Figures 25 and 26 respectively. These tests show that along with an increase in NO reductions, hydrogen also results in lower ammonia emissions. At high hydrogen injection rates, the NO levels begin to increase while the NH_3 levels in the combustion products continue to decrease.

The experimental results presented in this section are drawn from data summarized for each fuel type in Appendix C.

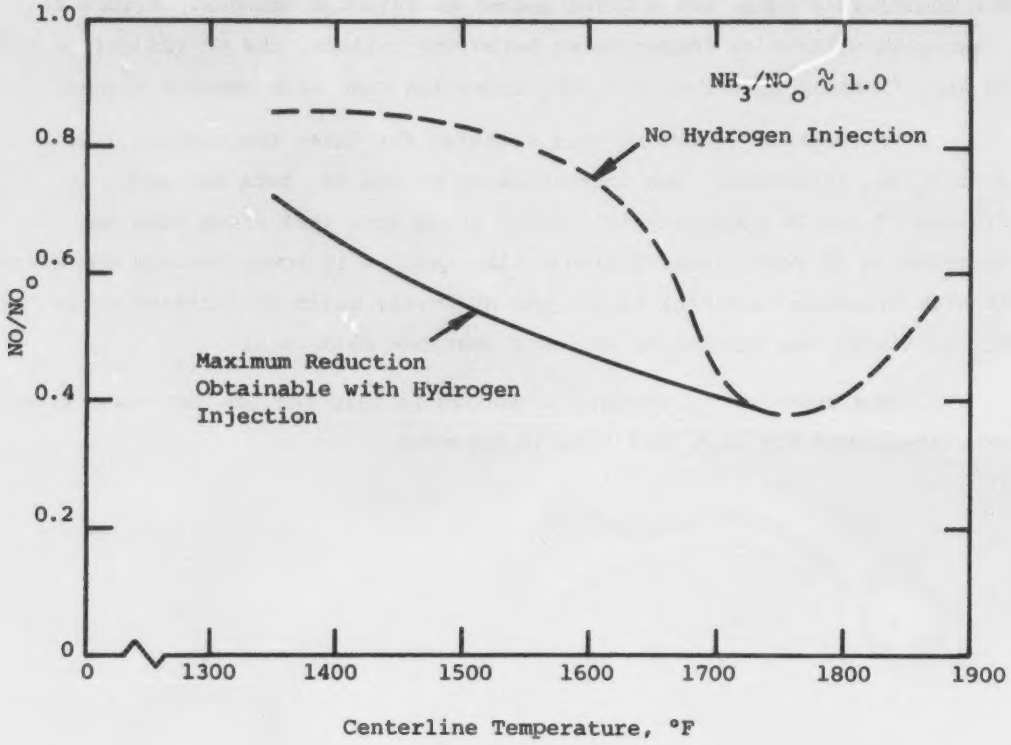


Figure 24. Cross plot of the optimum NO reduction for NH_3/NO_o = 1.0 (variable hydrogen injection), Pittsburgh coal.

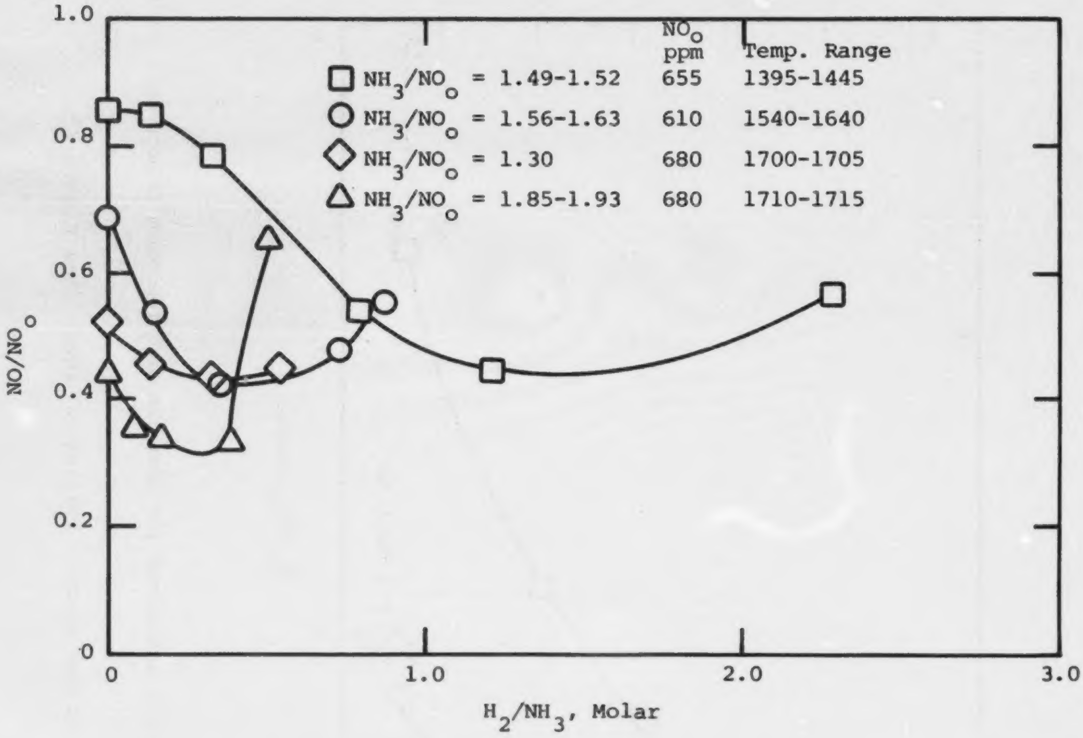


Figure 25. NO reductions with ammonia and hydrogen injection - Pittsburgh coal.

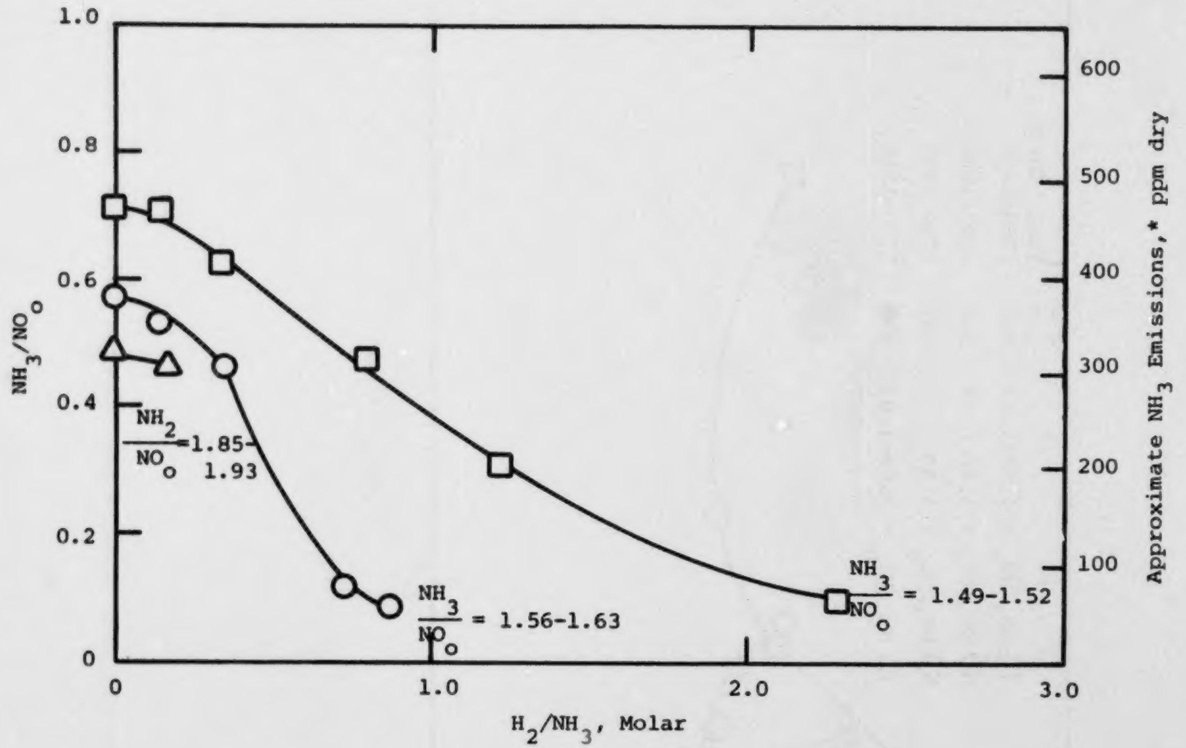


Figure 26. Ammonia emissions for ammonia and hydrogen injection - Pittsburgh coal.

*Based on the average initial NO level (See Figure 25.)

SECTION 4.0

CONCLUSIONS

1. NO reductions obtained with ammonia injection into coal-derived combustion products were comparable to those previously obtained in natural gas and oil-fired systems. On the order of 65% reductions in NO were obtained at an ammonia injection rate of one mole of ammonia per mole of NO.

2. The temperature dependence varied from coal to coal. The Navaho coal exhibited peak reductions at the lowest temperature, 1720 °F, while the Illinois coal showed peak reductions occurring at 1830 °F. No definitive reason could be found to explain this variation in temperature. The unexplained variation in optimum process temperature with coal type indicates that evaluation testing would be prudent in situations where maximum NOx control was desired and no previous experience was available for the coal in question.

3. In general, the ammonia emissions (or breakthrough) are comparable for all fuels tested during this program. The highest emissions of ammonia occur when the temperature of the combustion products at the point of injection was less than that required for optimum NO removal. With judicious selection of the temperature at the point of injection, nitric oxide reductions of 55% were achieved while limiting NH_3 emissions to the range 11 to 34 ppm.

4. Using injection rates of ammonia less than 2:1 NH_3/NO, no statistically significant changes in the cyanide or nitrate species concentrations were measured relative to the baseline case of no no ammonia injection. It was concluded that they are not byproducts of the deNOx process in coal-fired systems.

5. Within the accuracy of the experimental measurements, there was a tendency to reduce the SO_3 level in the combustion products during ammonia injection. However, due to the small changes in the sulfate levels with and without ammonia injection, the question of sulfate formation is inconclusive.

6. The addition of small quantities of hydrogen can be used to increase the NO reductions and decrease the ammonia emissions at temperatures lower than optimum.

7. At a given temperature and ammonia injection rate there exists an optimum rate of hydrogen injection. Further increase in this optimum rate results in decreases in the amount of NO removed. This optimum hydrogen injection rate increases as the temperature at the point of injection decreases.

8. These findings with NH_3 injection into coal-derived combustion products were in substantial agreement with previous experimental results with gas- and oil-fired systems (Refs. 2, 3) in terms of achievable NO reductions, ammonia emissions, and byproduct formation.

REFERENCES

1. Proceedings of the Stationary Source Combustion Symposium, Volume I - Fundamental Research, EPA-600/2-76-152a, p. I-14, June 1976.

2. Lyon, R. K., "Method for the Reduction of the Concentration of NO in Combustion Effluents using Ammonia," U.S. Patent No. 3,900,554, assigned to Exxon Research and Engineering Company, New Jersey, August 1975.

3. Lyon, R. K. and Longwell, J. P., "Selective, Non-Catalytic Reduction of NOx with NH_3," EPRI NOx Control Technology Seminar, San Francisco, California, February 5 and 6, 1976 (EPRI Special Report SR-39).

4. Muzio, L. J. and Arand, J. K., "Homogeneous Gas Phase Decomposition of Oxides of Nitrogen," EPRI Report FP-253, August 1976.

5. Muzio, L. J., Arand, J. K., and Teixeira D. P., "Gas Phase Decomposition of Nitric Oxide in Combustion Products," EPRI NOx Control Technology Seminar, San Francisco, California, February 5 and 6, 1976

6. Chedaille, J. and Braud, Y., Industrial Flames, Volume 1: Measurements in Flames, Edward Arnold Ltd., London, 1972.

7. Lyon, R. K., personal communication, 1977.

APPENDIX A

EXPERIMENTAL APPARATUS

SECTION A-1.0

EXPERIMENTAL APPARATUS AND PROCEDURE

The test equipment, shown in Figures A-1 through A-4, can be divided into five categories: (1) burners, (2) air supply, (3) fuel supply, (4) boiler furance, and (5) instrumentation. Each of these categories is discussed separately below.

A-1.1 TEST BURNER DESIGN

A Foster Wheeler burner currently being used in a modern coal-fired utility boiler was chosen as the basis for the laboratory scaled burner. The modeling approach used was to preserve the temperature, velocities, and volumetric heat release rate of the full size unit as well as geometrical similiarity of the burner. The scaled-down version of the full-size burner is shown schematically in Figure A-4.

A-1.2 AIR SUPPLY

The air supply system is shown schematically in Figure A-5.

Three venturi meters and one rotameter were used to measure the various air flows into the boiler. The total air flow was the sum of the flows measured by the "main air flow" venturi and the "tempering air" rotameter. Air from an indirect-fired preheater passed through the main air flow venturi, where the total mass flow of preheated air was measured. The preheated air was then split into two streams: one to supply part of the primary combustion air, and the other to furnish secondary air to the burner.

The solid fuel was added to the conditioned primary air just upstream of the burner. The primary air-coal mixture entered the burner tube tangentially, forming a vortex.

LEGEND - For Figures A-1 - A-3

1. Primary Air Duct
2. Primary Air Valve
3. NOx-Port Air Duct
4. NOx-Port Air Valve
5. NOx-Port Air Venturi
6. NOx-Port Air Flexible Hose
7. NOx-Port Air Injection Torus and Inlet Pipe, Variable Position
8. Water Injection Nozzle
9. Burner Support Cylinder
10. Air Register
11. Flame Detector
12. Ignitor
13. Burner
14. Ceramic Quarl - 5-1/2" Throat Diameter
15. Observation Door
16. Fire Brick 25" Inside Diameter
17. View Ports
18. Water Wall of Scotch Boiler
19. Steam Vent
20. Stainless Steel Liner 34" Inside Diameter
21. Fire Tubes (62 with Diameter 2-7/8")
22. Recirculation Gas Duct
23. Recirculation Gas Venturi
24. Damper
25. Stack

Instrumentation

Temperatures:

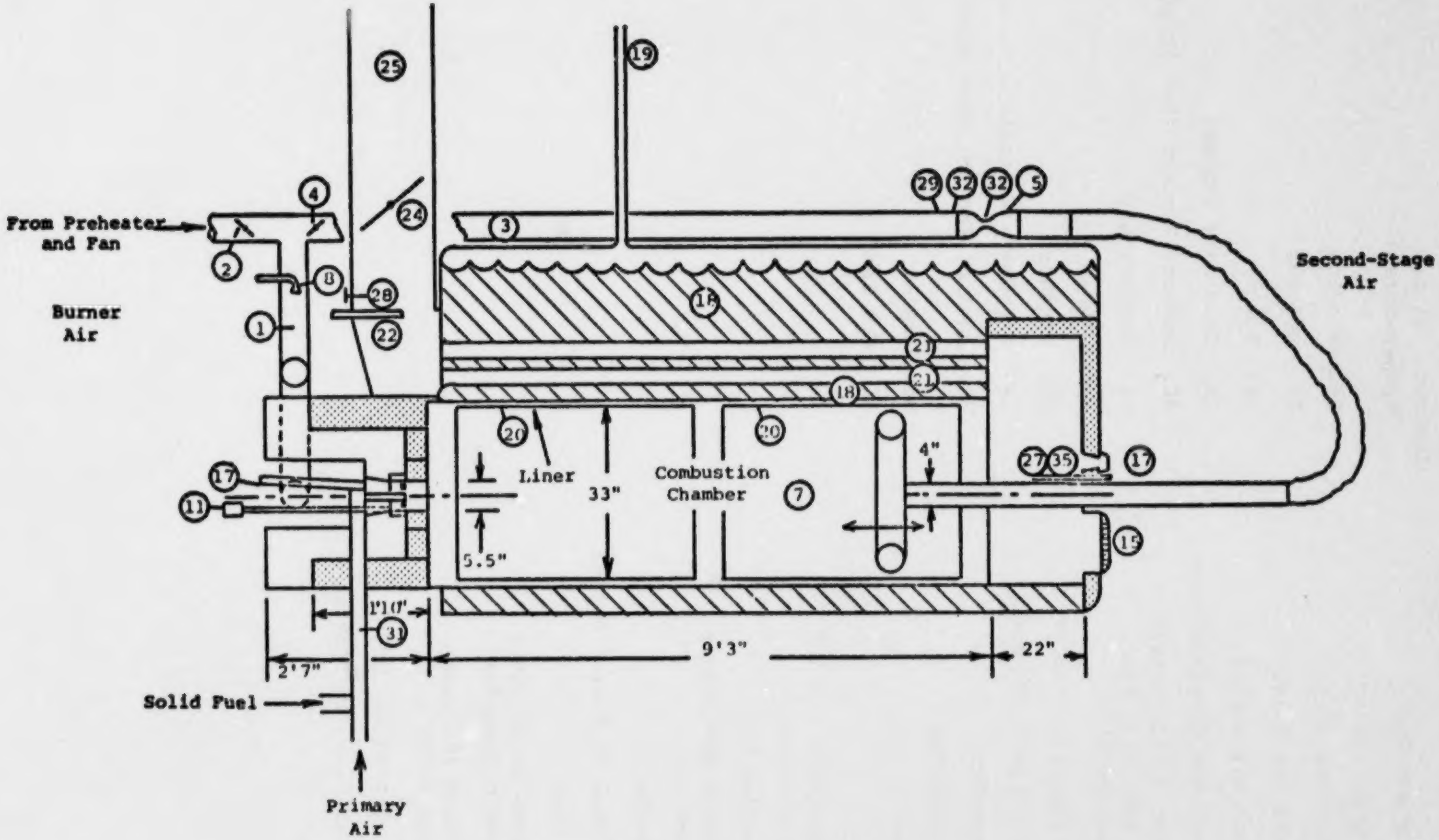
26. Windbox
27. Hot End
28. Stack
29. Secondary Venturi
30. Recirc. Venturi (Not Shown)
31. Primary Air

Pressures:

32. Windbox
33. Secondary Venturi
34. Recirc. Venturi (Not Shown)

Gas Sample:

35. Hot End


From Preheater and Fan
Burner Air
Second-Stage Air
Solid Fuel
Primary Air
Liner
Combustion Chamber
33"
5.5"
4"
1'10"
2'7"
9'3"
22"
①
②
③
④
⑤
⑦
⑧
⑪
⑮
⑰
⑱
⑲
⑳
㉑
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㉟

Figure A-1. Schematic of eighty-horsepower boiler.

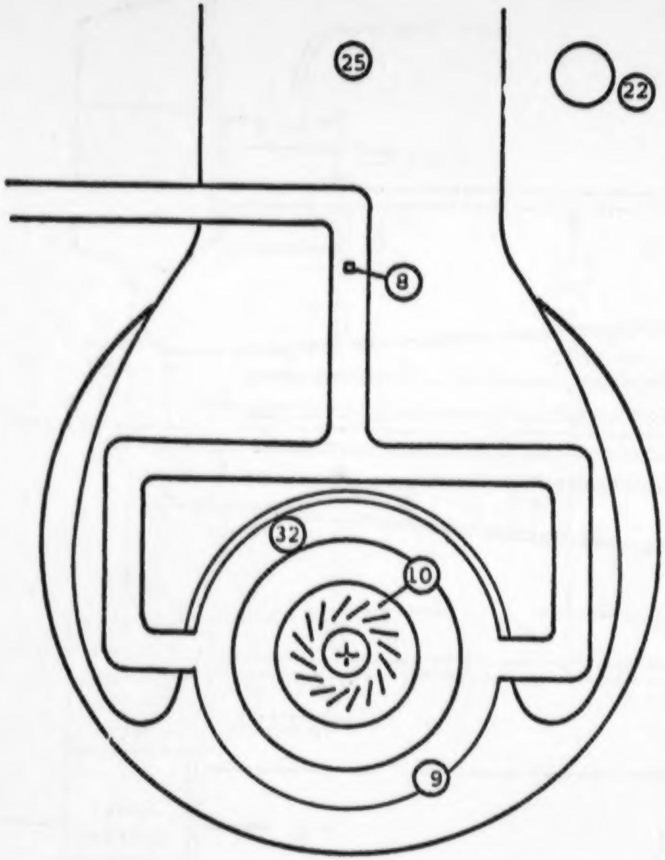

25
22
8
32
10
9

Figure A-2. Cross section through windbox.

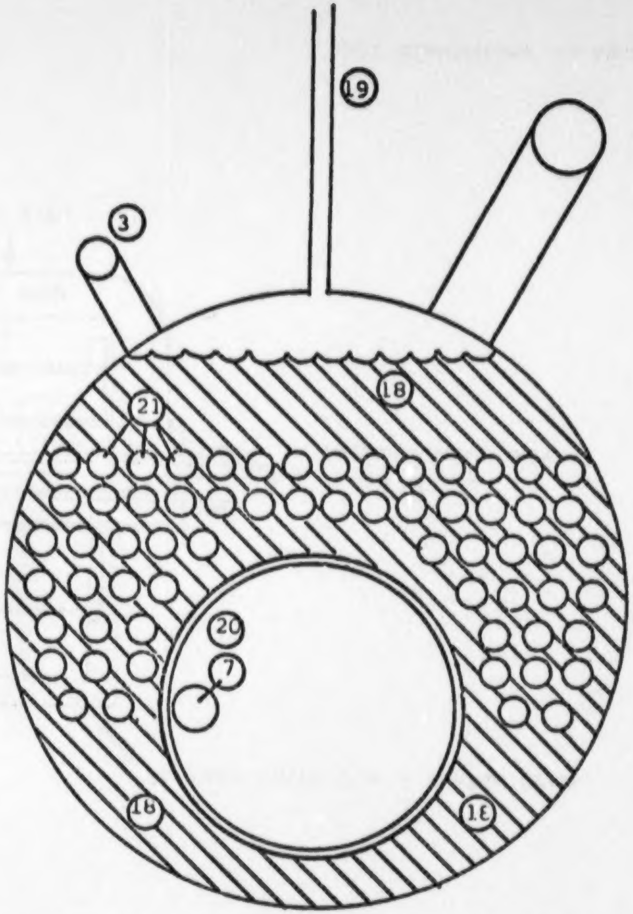

19
3
18
21
20
7
18
18

Figure A-3. Cross section through firebox.

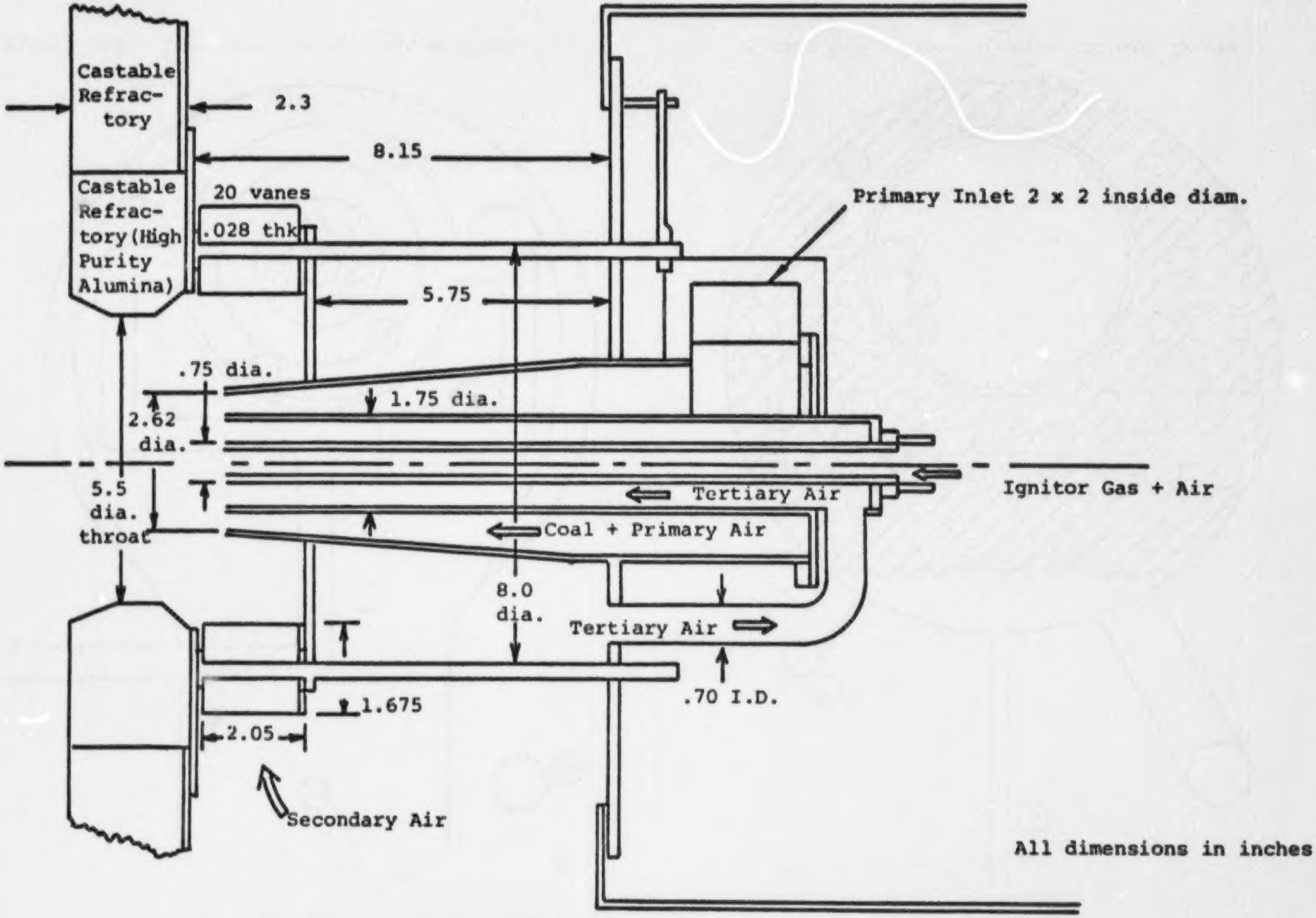

Castable Refractory
2.3
8.15
Castable Refractory (High Purity Alumina)
20 vanes
.028 thk
Primary Inlet 2 x 2 inside diam.
5.75
.75 dia.
1.75 dia.
2.62 dia.
5.5 dia. throat
Ignitor Gas + Air
Tertiary Air
Coal + Primary Air
8.0 dia.
Tertiary Air
.70 I.D.
1.675
2.05
Secondary Air
All dimensions in inches

Figure A-4. Small-scale version of a full-scale coal burner.

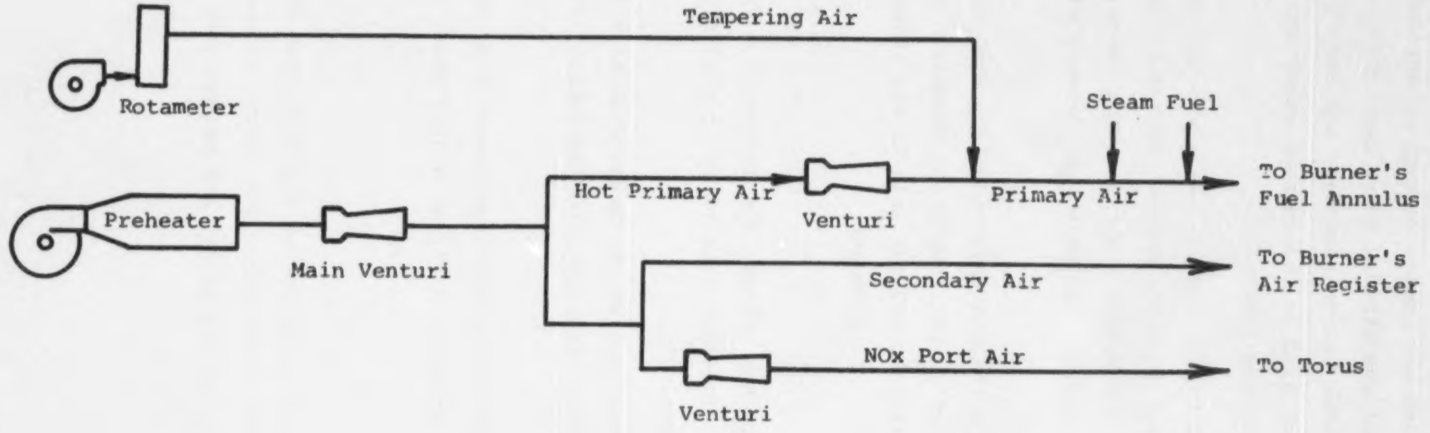

Tempering Air
Rotameter
Steam Fuel
Preheater
Main Venturi
Hot Primary Air
Venturi
Primary Air
To Burner's Fuel Annulus
Secondary Air
To Burner's Air Register
NOx Port Air
Venturi
To Torus

Figure A-5. Schematic of combustion air supply.

The remainder of the preheated air passed through an insulated duct to a point about ten feet upstream of the windbox where two valves were used to regulate the flow split between burner secondary and second-stage (NOx-port) air. This feature was not used in the current study and the second-stage air torus (#7, Fig. A-1) was removed.

The secondary air (delivered to the burner) was split into two streams which entered the windbox from opposite sides. This air flowed into the combustion chamber through the burner's air register vanes, which imparted a swirl to the flow in the same direction as the primary mixture's swirl.

The second-stage air passes through a venturi meter, then into a pipe leading to a perforated torus inside the combustion chamber. The air can be injected from the torus radially toward the axis of the combustion chamber through 32 orifices, each 9/16" in diameter.

A-1.3 FUEL SUPPLY

The solid fuels were fed into the primary air stream by a Vibra-Screw feeder with a vibrating-bottom bin. The feed rate of the 1-1/2" diameter spring-type screw was continuously variable.

The feed flow included fluctuations which varied with each fuel. Fluctuations in flue gas excess O_2 indicated fuel-flow variations of as much as ± 5% in some cases.

The natural gas fuel was supplied by the high-pressure supply from the meter (5 psig). Flow rate was varied manually by a gate valve downstream of a rotameter.

A-1.4 BOILER FURNACE

The boiler shell is an 80 horsepower Scotch dry-back type boiler originally designed for low combustion intensity. The steam produced was vented at one atmosphere. Schematics of the boiler and burner were given in Figures A-1 through A-4.

The boiler's combustion chamber was fitted with a stainless steel liner to give wall temperatures of approximately 800 °F, which is typical for the combustion chambers of utility and large industrial boilers.

The fly ash was removed from the flue gas by a reverse-pulse baghouse. Sulfur oxides were dispersed by discharging the ash-free products (through an induced-draft fan) to a 42-ft high stack.

A valve at the baghouse inlet was used to maintain the boiler pressure within 0.1 IWG of atmospheric pressure, thus minimizing leakage into or out of the system.

A-1.5 INSTRUMENTATION

Flue gas samples were withdrawn by a diaphragm-type vacuum pump at three points just upstream of the boiler's draft damper. Each of these sample lines had a porous metal filter at its end to prevent fly ash from being drawn into the sample line. The lines were periodically backflushed to prevent blockage of the filter.

One of the sample lines was used for the supply to the SO_2, NOx, and UHC analyzers. The other two sample lines were fed to water-filled bubblers where the sample flow rate from each line were approximately balanced by adjusting the bubbling rates to be approximately equal. The samples were then blended into a single stream which was passed through a filter and a Hankison Series E refrigerator-type drier to remove water vapor.

Concentrations on a dry basis of NO, O_2, CO, and CO_2 were measured continuously using a Thermo Electron Corp. chemiluminescent nitric oxide analyzer with a NO_2 converter, a Beckman Model 742 oxygen electrolytic analyzer, a Horiba Model PIR2000 nondispersive infrared carbon monoxide analyzer, and a Horiba Model AIA-21 nondispersive infrared carbon dioxide analyzer. These instruments were calibrated several times per hour using known calibration gases. The outputs of these instruments were monitored continuously on a Texas Instruments recorder.

Sulfur dioxide was measured using a Dupont Model 411 photometric analyzer. The Thermo Electron NOx analyzer was used with a NO_2 moly converter to obtain total NOx. The converter was necessary to prevent catalytic conversion of NH_3 to NO in the converter which can occur with a stainless steel converter.

Ammonia, cyanide, and nitrates were collected and analyzed with specific ion electrodes as discussed in Reference 4.

A Beckman Model 402 hydrocarbon analyzer was used to measure unburned hydrocarbons.

Temperature measurements other than the gas temperature in the main firetube were made using chromel-alumel thermocouples. The temperature probe used to determine the gas temperatures at the point of ammonia injection were described previously in Section 2.3.1.

A-1.6 AMMONIA INJECTORS

The basic schematics and a detailed design of the ammonia injectors are given in Figures A-6 through A-8. With the arrangement shown, the ammonia can be injected at either a single location on the boiler centerline (with six tip injection points) or at five locations as shown in Figure A-6 (each with six tip injection points). All injection orifices are located perpendicular to the average flue gas streamlines (radial injection).

To maintain the integrity of the injectors, they were fabricated from stainless steel and water cooled. They were sized for 2 gpm per injector flow rate at the most adverse temperature conditions with a maximum of 4 ft of each injector exposed to the hot gases.

Nitrogen was used as a carrier gas for the ammonia to assist in optimum penetration and mixing. Each injector ammonia flow rate as well as the total ammonia and nitrogen flow rates were measured as shown in Figure A-8.

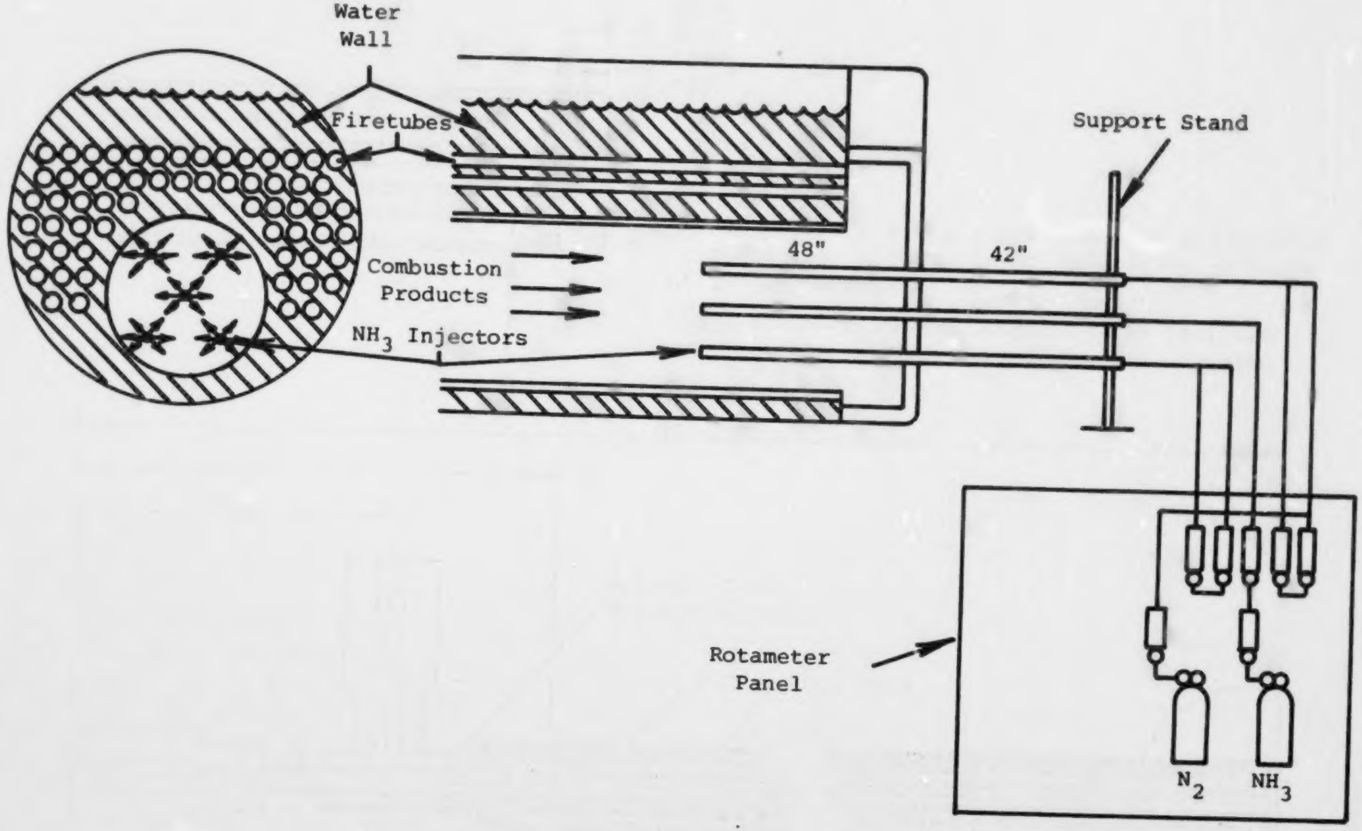
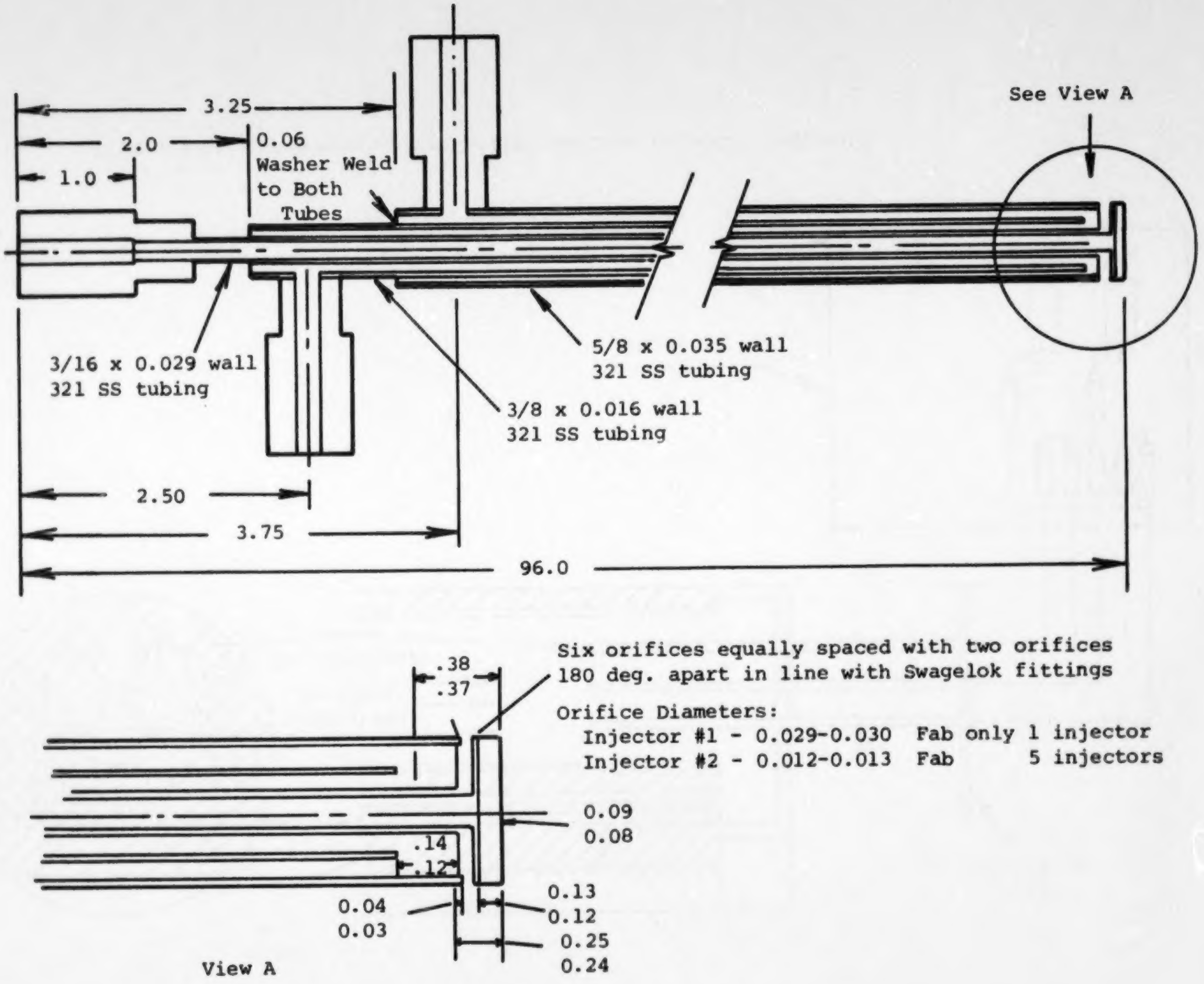
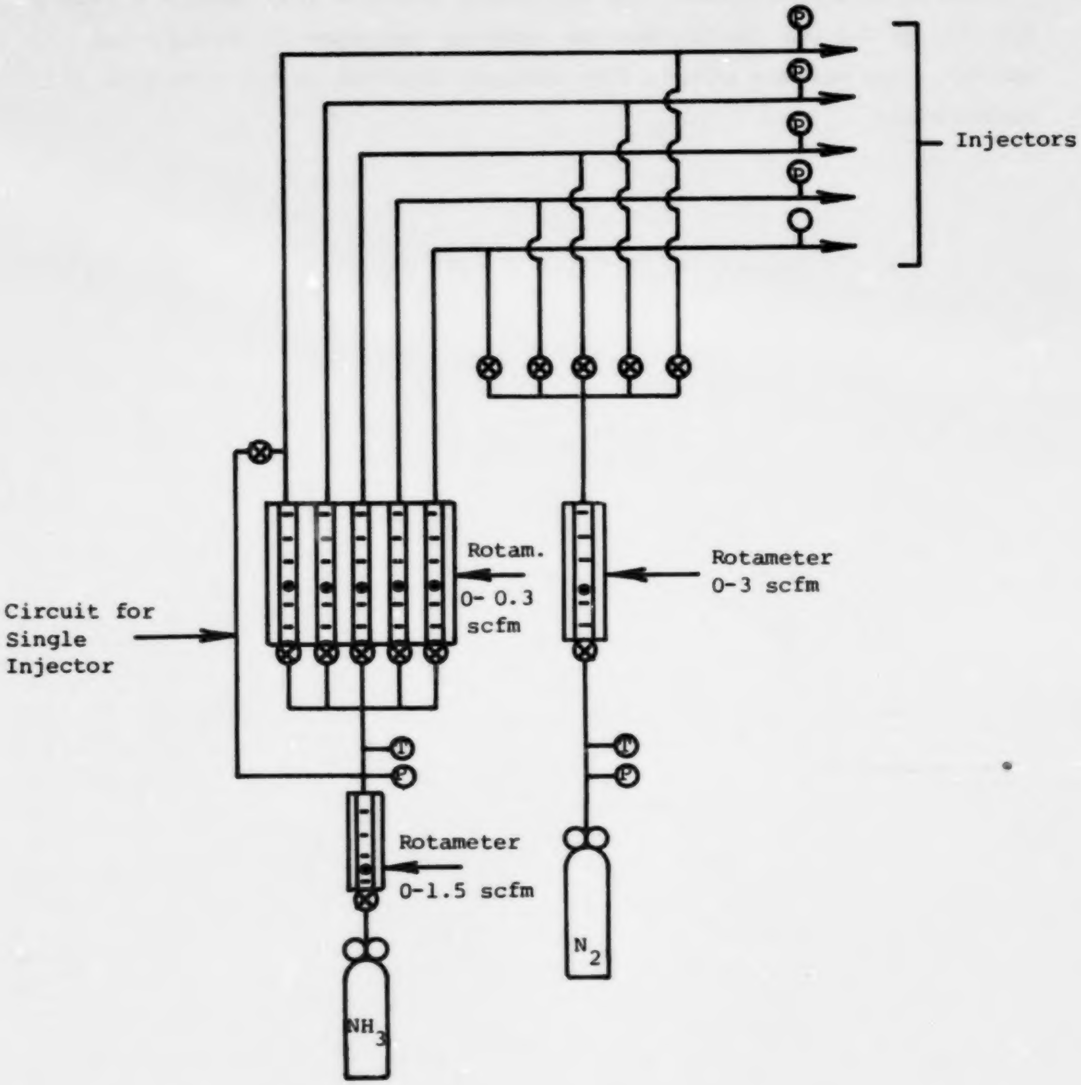

Water
Wall
Firetubes
Combustion
Products
NH$_3$ Injectors
48"
42"
Support Stand
Rotameter
Panel
N$_2$
NH$_3$

Figure A-6. Eighty-horsepower boiler ammonia injection schematic.



See View A
3.25
2.0
1.0
0.06
Washer Weld to Both Tubes
3/16 x 0.029 wall 321 SS tubing
3/8 x 0.016 wall 321 SS tubing
5/8 x 0.035 wall 321 SS tubing
2.50
3.75
96.0
.38
.37
Six orifices equally spaced with two orifices 180 deg. apart in line with Swagelok fittings
Orifice Diameters:
Injector #1 - 0.029-0.030 Fab only 1 injector
Injector #2 - 0.012-0.013 Fab 5 injectors
0.09
0.08
.14
.12
0.04
0.03
0.13
0.12
0.25
0.24
View A

Figure A-7. Water cooled ammonia injection system.



P
P
P
P
Injectors
Rotam.
0- 0.3
scfm
Rotameter
0-3 scfm
Circuit for
Single
Injector
T
P
T
P
Rotameter
0-1.5 scfm
N2
NH3

Figure A-8. Ammonia injection flow metering system.

The ammonia injector orifices were sized to give sonic flow at maximum ammonia flow rates. The calculated pressure drop through a single injector is 7.9 psi for the maximum combined flow rate of nitrogen and ammonia. The maximum ammonia flow rate per injector is 0.3 scfm (air equivalent).

APPENDIX B

SULFATE AND SO_3 EMISSION MEASUREMENT PROCEDURE

SECTION B-1.0

SAMPLING TRAIN AND SAMPLING PROCEDURES

Figure B-1 shows a schematic of the sulfate and SO_3 sampling system. It consisted of a heated quartz probe, a glass tube adapter for introducing ammonia in the probe, a heated box which contains the filter holder, acid washed asbestos fiber filter, impinger train, ice bath, dry gas meter, and a pump.

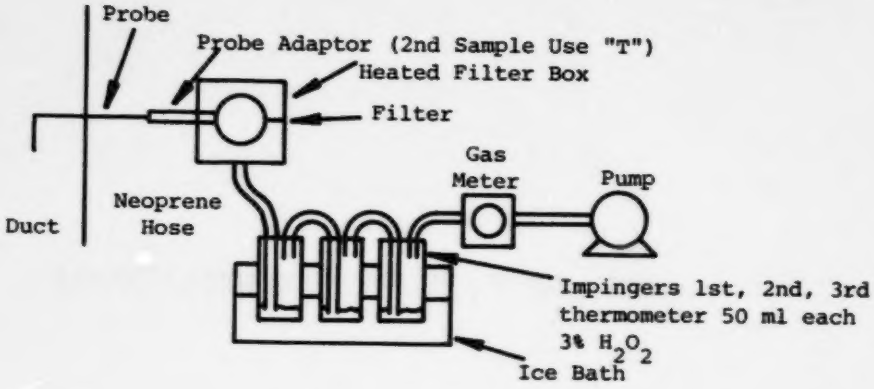

Probe
Probe Adaptor (2nd Sample Use "T")
Heated Filter Box
Filter
Gas Meter
Pump
Duct
Neoprene Hose
Impingers 1st, 2nd, 3rd thermometer 50 ml each 3% H_2O_2
Ice Bath

Figure B-1. Sulfate sampling equipment.

A 30 cfm sample was collected at 1 cfm from the stack during which time the probe was maintained at 205 °F, the heated box was maintained at 310 °F, and the impingers at 70 °F. The impingers contain a solution of 3% hydrogen peroxide in water.

Two sampling modes were used. One mode collects the sample directly from the stack without any dilution or additions to the probe. In the second mode, ammonia is bled into the probe before the heated filter to react with any free SO_3 that might be present to form $(NH_4)_2 SO_4$ which would then be collected on the filter. Table B-1 contains a list of compounds and their melting points that potentially could be formed with the ammonia.

TABLE B-1. AMMONIUM COMPOUNDS

Compound	mp (°F)	bp (°F)
ammonium sulfate $(NH_4)_2SO_4$	d 454	---
ammonium bisulfate $(NH_4)HSO_4$	295.8	d
ammonium sulfamate $NH_4NH_2SO_3$	256.4	d 319.4
ammonium sulfite $(NH_2)SO_3 \cdot H_2O$	d 139.4 - 157.4	sub 301.4
ammonium bisulfite NH_2HSO_3	sub 301.4 in N_2	---
ammonium hydrosulfide NH_4HS	244 150 atm	1623 19 atm
ammonium monosulfide $(NH_4)_2S$	d	---

d = decomposes; sub = sublimes

Following the sample collection, the probe, connections, and front half of the filter holder were washed with distilled water. The filter was added to these washes and reduced to pulp to dissolve all of the collected sulfate. The back half of the filter holder and connections were washed with distilled water and added to the impinger condensate. The impingers contain the SO_2 component and the filter contained either the SO_3 or SO_3 reacted to NH_4SO_4 with added probe ammonia.

B-1.1 SO_3 AND NEUTRAL SULFATE ANALYSIS

The gravimetric procedure was used to determine the neutral sulfates. In this technique, the initial filter wash is filtered through a Whatman #4 filter paper. The filtrate is heated to near boiling and concentrated ammonium hydroxide is added. This solution is then filtered again to remove iron and aluminum and made acidic with concentrated hydrochloric. Ten milliliters of a 10% barium chloride solution is added to the warm acidic solution and allowed to stand overnight to precipitate $BaSO_4$. This solution is then passed through a tare-weighed Gooch crucible. The crucible is then baked at 800 °C for 1 hour, cooled, and weighed to determine the resultant $BaSO_4$. The amount of SO_3 equivalent sulfate is calculated using the following expression:

$$ppm_{SO_3,wet} = \frac{10{,}400\ (\text{weight sulfate as } SO_3)}{\text{standard cubic feet of sampled gas}}$$

The level of sulfur trioxide in the flue gas was obtained by assuming that the ammonia injected into the probe reacted with all of the SO_3. Thus the difference between the sulfate determined with and without NH_3 injected into the probe is the concentration of SO_3.

The presence of free SO_3 was detected by adding a few drops of methyl orange to the filter wash solution. If the indicator turned the solution red, then free SO_3 was present and a standard acid-base titration procedure using 0.01 N sodium hydroxide titrant was performed.

APPENDIX C

DATA SUMMARY

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NATURAL GAS FUEL

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Radial	Temperature °F	Aspiration Pct
1-26-77	1045	329	4.5	4	℄	1582	0
						1746	15
						1797	25
						1810	35
						1815	45
						1835	55
	1125		4.4			1835	65
						1837	75
	1205			3		1510	0
						1556	15
						1676	25
						1693	35
						1724	70
						1658	16
						1530	0
	1315			2		1443	0
						1628	15
						1655	25
						1677	35
						1742	70
	1430			2½		1476	0
						1613	15
						1680	25
						1703	35
						1730	70
	1520			4½		1632	0
						1841	16
						1887	25
						1909	35
						1863	75

NATURAL GAS FUEL

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Radial	Temperature °F	ASPIRATION PCT
1-27-77	1053	329	4.5	2	℄	1426	0
						1647	20
		↓	↓			1724	75
	1200	355	5.5			1417	0
						1646	20
		↓	↓	↓		1716	70
	1305	355	5.3	3		1508	0
						1717	20
				↓		1790	70
				4		1580	0
						1767	20
		↓	↓	↓		1833	70
	1525	390	6.7	4½		1604	0
						1777	20
				↓		1853	70
	1555		9.8	2		1303	0
						1499	20
		↓	↓	↓	↓	1567	70
1-28-77	1015	346	7.4	2	℄	1299	0
						1533	20
					↓	1607	70
					8	1702	
					4	1550	
					6	1719	
					2	1630	
		↓	↓	↓	℄	1594	↓

NATURAL GAS FUEL

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Temp. Probe Location Radial	Temperature °F	ASPIRATION PCT
1-31-77	1555	332	7.0	4	℄	1424	70
					4	1591	
					8	1342	
					9	1288	
					5	1718	
					6	1431	
					7	1512	
					2	1470	
					3	1473	
		↓	↓	↓	℄	1407	↓
2-1-77	1035	390	5.1	3	℄	1503	70
						1581	
						1608	
					↓	1736	
					4	1760	
					4½	1763	
					8	1665	
					8½	1647	
					2	1783	
					2½	1766	
					6	1672	
					7	1481	
					6½	1535	
			↓	↓	℄	1733	
	1135		5.2	2		1631	
				2½		1687	
				3		1745	
				4		1856	
		↓	↓	4½	↓	1914	↓

NATURAL GAS FUEL

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Radial	Temperature °F	ASPIRATION PCT
2-1-77		390	5.2	4	℄	1846	70
					8	1785	
					9	1671	
					4	1857	
					5	1798	
					6	1785	
					7	1649	
					2	1885	
					3	1650	
				↓	℄	1790	↓
				2		1271	0
				3		1369	
				4		1461	↓
				2		1612	68
				3		1725	
		↓	↓	4	↓	1823	↓
2-7-77	1015	391	5.0	3	℄	1671	65
	1240	412	5.1			1665	
	1320	284	5.05	↓	↓	1615	↓

NATURAL GAS FUEL

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Temp. Probe Location Radial	Temperature °F	ASPIRATION PCT
2-28-77	1000	385	4.9	4½	CL	1843	65
					8	1884	
					9	1813	
					4	1953	
					5	1893	
					6	1896	
					7	1801	
					2	1800	
				↓	3	1806	
				4	CL	1825	
				3½		1773	
				3		1703	
				2½		1655	
				2	↓	1557	
					4	1640	
					5	1543	
					6	1473	
					7	1282	
		↓	↓	↓	2	1699	↓

UTAH COAL A

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Temp. Probe Location Radial	Temperature °F
3-4-77	1325	LIGHT OFF				
	1510	389	4.9	2	a	1325
	1525	391		2½		1387
	1545			3		1440
	1558			3½		1492
	1612	↓	↓	4		1534
	1620	397	4.8	4		1552
	1640	↓	↓	2	↓	1364
3-7-77	1425	397	5.0	4	a	1600
					4	1586
					5	1580
					8	1628
					9	1631
					6	1660
					7	1676
					2	1620
					3	1590
			↓		a	1585
	1635		5.3			1548
				↓		1821 Asp
				2		1370
		↓	↓	↓	↓	1520 Asp
3-8-77	1620	398	5.4	2	a	1352
				↓		1702 Asp
				4		1580
		↓	↓	↓	↓	1884 Asp

UTAH COAL A

*1 Heat Shield [illegible]

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Temp. Probe Location Radial	Temperature °F
3-25-77	1330	400	5.4	2	CL	1320
	1350			↓		1603 Asp
	1415			3		1392
	1435			4		1455
	1445			↓		1727 Asp
	1451			2	↓	1616 [illegible]
	1520			4	8	1451
	1535		↓		4	1432
	1545		4.9		4	1512
	1605				5	1525
					7	1489
		↓	↓	↓	3	1460
5-12-77	1025	LIGHT OFF				
	1130	393	5.5	2	CL	1301
	1135			↓		1710 Asp
	1137			3		1795 Asp
	1140		↓	4		1843 Asp
	1158		5.2			1520
	1320		5.1			1555
	1322	↓	↓	↓		1849 Asp
	1400	327	5.6	2		1273
	1405		5.7	↓		1585 Asp
	1425		5.5	4		1453
	1427		↓	↓		1791 Asp
	1453		5.6	2		1262
	1455		5.8	↓		1578 Asp
	1505	↓	5.5	3	↓	1704 Asp

NAVAHO COAL B

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Temp. Probe Location Radial	Temperature °F
3-31-77	0910	LIGHT	OFF			
	1110	372	5.4	2	9	1280
	1115	↓	↓	↓	↓	1500 ASP.
	1125	↓	↓	4	↓	1443
	1130	↓	↓	↓	↓	1630 ASP

ILLINOIS COAL C

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Temp. Probe Location Radial	Temperature °F
4-20-77	0905	LIGHT	OFF			
	0935	362	5.4	2 1/4	℄	1260
	1000		5.2	2		1220
				↓		1630 Asp
	1010			4		1518
				↓		1885 Asp
	1025			2		1290
	1043			4		1523
						1880 Asp
	1315					1577
		↓	↓	↓	↓	1900 Asp
4-25-77	0920	LIGHT	OFF			
	1345	368	4.8	4	℄	1646
	1355				4	1640
	1402				5	1624
	1412				8	1652
	1420				9	1647
	[illegible]				7	1652
	[illegible]				3	1647
	1450	↓	↓	↓	℄	1916 Asp
5-27-77	[illegible]	LIGHT	OFF			
	1417	364	4.8	2	℄	[illegible] Asp
	1422			3		[illegible]
	1425	↓	↓	4	↓	1939

PITTSBURG SEAM 8 COAL D

Test Date	Time	Q_A scfm	O_2 Pct	Temp. Probe Location Axial	Radial	Temperature °F
5-16-77	1120	LIGHT	OFF			
	1255	360	5.0	2	CL	1134
	1305		4.9	↓		1414 Asp
	1320		5.1	4		1424
	1335		5.0	↓		1757 Asp
	1340		↓	3		1651 Asp
	1558		5.2	2		1253
	1600	↓	↓	↓	↓	1525 Asp
	LOW	TEMPE	[illegible]	RUNS	ALL HEA	T SHIELDS [illegible]
6-1-77	1230	LIGHT	[illegible]			
	1347	325	4.5	2	CL	940
	1357					463
	1409					974
	1420					985
	1427			↓		1277 Asp
	1430			3		1341 Asp
	1433	↓	↓	4	↓	1163 Asp
6-2-77	0855	LIGHT	OFF			
	[illegible]	326	5.0	3	CL	1462 Asp
	1040				8	1324 Asp
	1042				9	1544 Asp
	1044				4	1367
	1046				5	1335
	1115			↓	CL	1522
	1125			2½		[illegible]
	1130			2		1354
	[illegible]	↓	↓	↓	↓	1455

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_2 ppm	Wet SO_2 ppm	NO ppm	N_2O ppm	UHC ppm	Molar Ratios NH_3/NO_0	NO/NO_0	N_2/NH_3
2-1-77	1502	NAT	GAS	[illegible]		[illegible]	.186	0	0	[illegible]	5.1	—	9.3	—	—	—	—	—	—	—	0	1.0	0
[illegible]	[illegible]							.051		[illegible]	[illegible]										.47	.87	
[illegible]-ΔP	[illegible]							.171		405	5.0										1.03	.755	
	[illegible]							[illegible]		375											1.69	.71	
								[illegible]		[illegible]											[illegible]	.64	
	[illegible]			[illegible]				[illegible]		[illegible]											[illegible]	.625	
	1545							[illegible]		[illegible]											[illegible]	[illegible]	
	[illegible]							.191		[illegible]											1.03	[illegible]	
	1550							[illegible]		420	5.0										[illegible]	.77	
	[illegible]							0		[illegible]											0	1.0	
	[illegible]			[illegible]			.151	[illegible]		410	5.1										.46	.74	
	1556							[illegible]		310	5.0										.77	.56	
	[illegible]							[illegible]		[illegible]	4.9										1.51	.45	
	[illegible]							[illegible]		[illegible]	4.9										[illegible]	.37	
	[illegible]						.234	0		[illegible]	5.1										0	1.0	
	[illegible]							[illegible]		[illegible]	5.0										.40	[illegible]	
	[illegible]							.171		[illegible]	[illegible]										.92	[illegible]	
	[illegible]							.218		[illegible]	[illegible]										1.41	.37	
	[illegible]							[illegible]		[illegible]	[illegible]										[illegible]	[illegible]	
	[illegible]							0		[illegible]	[illegible]										0	1.0	
	[illegible]							.415		160	5.0										1.96	.29	
	[illegible]			1925				[illegible]		[illegible]	[illegible]										1.96	.70	
2-2-77	[illegible]	Nat	Gas	[illegible]		[illegible]	.174	0	0	[illegible]	5.1	10	9.5	—	—	—	—	—	—	—	0	1.0	0
[illegible]	[illegible]							[illegible]		405	5.1										.46	.555	
[illegible]	[illegible]							[illegible]		[illegible]	5.1										1.07	.785	
	1031							[illegible]		[illegible]	5.1										1.65	.375	
	1033							.39		320	5.1										[illegible]	.655	
	[illegible]							0		[illegible]	5.1										0	1.0	
	1039			[illegible]				.091		[illegible]	5.1										.46	[illegible]	
	1041							[illegible]		[illegible]	5.1										1.07	.675	
	1043							[illegible]		[illegible]	5.1										1.55	.57	
	1045							.39		[illegible]	5.1										[illegible]	.53	

KVB

		Primary		Centerline		Flow Rates (scfm)				Stack Emissions											Molar Ratios		
										Dry							Wet						
Test Date	Time	Fuel	Type	Gas	Temp	Q_{AIR}	Q_{NO}	Q_{NH_3}	Q_{H_2}	NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	SO_2 ppm	NO ppm	NOx ppm	UHC ppm	$\frac{NH_3}{NO_o}$	$\frac{NO}{NO_o}$	$\frac{N_2}{NH_3}$
2-2-77	1047	NAT	GAS	1995		390	.121	0	0	510	5.1	10	9.5	—	—	—	—	—	—	—	0	1.0	0
Single Injection	1049							.091		355	5.0										.45	.895	
60-LP	1051							.186		310	5.0										1.08	.635	
	1053							[illegible]		265	5										1.59	.52	
	[illegible]						↓	[illegible]		212	5.0										2.15	.41	
	1115						.145	.446		210	5.0										2.35	.405	
	1117							.50		220	4.9										2.64	.385	
	1119							.37		[illegible]											1.97	.46	
	1121							.232		[illegible]											1.26	.52	
	1123							.161		252											.56	.67	
	[illegible]							0		[illegible]											0	1.0	
	1127							.494		350											1.05	.67	
	1129							.218		365											1.16	.58	
	1131							[illegible]		270											1.34	.55	
	1133							[illegible]		[illegible]											1.57	.456	
	1135							.311		[illegible]											1.66	.44	
	1137							.165		[illegible]											.59	.55	
	1139							.171		300											.91	.57	
	1141							[illegible]		[illegible]											.95	.61	
	[illegible]							.186		[illegible]											.97	.55	
	1147			↓			↓	[illegible]		[illegible]											1.0	.666	
	1149			[illegible]			[illegible]	0		[illegible]											0	1.0	
	[illegible]						.156	0		520											0	1.0	
	1157							.341		360											.43	.69	
	1159							.186		[illegible]											1.0	.535	
	1201							.205		235											1.55	.45	
	1203							.33		[illegible]											2.1	.39	
	[illegible]			↓			↓	0		530	↓										0	1.0	
	[illegible]			[illegible]			.121	0		510	5.1										0	1.0	
	1327							.095		425											.47	.855	
	1334							2		375											1.10	.735	
	1337							.322		330											1.77	.625	
	1340			↓			↓	.465	↓	290	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	2.63	.57	↓

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_o}$	$\frac{NO}{NO_o}$	$\frac{N_2}{NH_3}$
2-2-77	1342	[illegible]	Gas	[illegible]		330	.176	0	0	[illegible]	5.1	10	9.3	—		—	—	.		--	0	1.0	0
Single Injection	[illegible]							.085		[illegible]											[illegible]	.78	
-9-ΔP	1347							.20		290											1.10	.56	
	1349							.32		220											1.80	[illegible]	
	1352							.509		180											3.86	.36	
	1355			↓				0		[illegible]											0	1.0	
	1400			1615				.035		435											.48	.81	
	1403							.203		330											1.14	.66	
	1406							.325		[illegible]											1.82	.59	
	1409							.536		235											2.0	.47	
	1411			↓				0		495											0	1.0	
	1415			1725				.0665		355											.48	.72	
	1418							.211		[illegible]											1.18	.45	
	1421							.321		[illegible]											2.15	[illegible]	
	1425							.416		[illegible]											[illegible]	.203	
	1428			↓		↓	↓	0	↓	[illegible]	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	0	1.0	↓
2-2-77	1530			1725		330	.178	0	0	500	5.0	10	9.3	—	—	-	—	—	—	--	0	1.0	0
2 Injectors	1532							.083		350											.46	.70	
	1534							.191		230											1.06	.46	
	1536							.298		160											1.67	.32	
	1538			↓			↓	.40		95											2.24	.19	
	1540			1825			.176	0		495											0	1.0	
	1542							.083		300											.47	.606	
	1544							.191		160											1.08	.323	
	1546							.298		115											1.69	.232	
	1548			↓				.40		79											2.27	.166	
	1550			1775				0		495											0	1.0	
	1552							.083		300											.47	.65	
	1554							.191		200											1.08	.405	
	1556							.298		140											1.69	.283	
	1558							.40		110											2.27	.222	
	1559			↓		↓	↓	0	↓	490	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	0	1.0	↓

C-15

Test Date	Time	Primary		Centerline		Flow Rates (scfm)				Stack Emissions											Molar Ratios		
										Dry							Wet						
		Fuel	Type	Gas	Temp	Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	SO_2 ppm	NO ppm	NOx ppm	UHC ppm	$\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{N_2}{NH_3}$
2-4-77	1437	NAT	GAS	1725		375	.185	0	0	515	5.85	—	8.7	—	—	—	—	—	—	—	0	1.0	0
5 INJECTORS	1441			|		|	|	.187	0	260	|										1.01	.505	|
N_2 VARIATION	1446			|		|	|	.202	.324	210	|										1.09	.406	|
	1448			|		|	|	.219	.7	150	↓										1.18	.29	|
	1452			|		|	|	.25	1.18	140	5.75										1.35	.272	|
	1456			|		|	|	.285	1.99	127	↓										1.54	.247	|
	1500			|		|	|	.305	2.2	80	5.8										1.66	.155	|
	1503			|		|	.184	0	0	525	5.85										0	1.0	|
	1510			|		|	|	.118	0	260	|										.94	.475	|
	1517			|		|	|	.176	.319	230	↓										.93	.44	|
	1520			|		|	|	.178	.69	225	5.8										.96	.39	|
	1523			|		|	|	.157	1.15	190	5.75										.94	.362	|
	1526			|		|	|	.162	1.76	175	5.8										.89	.334	|
	1529			|		|	↓	.164	2.13	180	|										.87	.343	|
	1531			↓		↓	.194	0	0	540	5.75	↓	↓	↓	↓	↓	↓	↓	↓	↓	0	1.0	↓
				[illegible]	AXIA. [illegible]																		
2-4-77	1535	NAT	GAS	STA	CK	325	—	—	—	520	5.85	—	8.7	—	—	—	—	—	—	—	—	—	—
5 INJECTORS	1537			1	2	|	|	|	|	525	↓										|	|	|
NO FLOWS	1538			|	2½	|	|	|	|	525	[illegible]												
AT INJECTORS	1539			|	3	|	|	|	|	525	5.6												
	1540			|	3½	|	|	|	|	530	5.55												
	1541			↓	4½	|	|	|	|	535	5.6												
	1542			STA	CK	|	|	|	|	540	5.85												
	1544			STA	CK	|	|	|	|	520	5.85												
	1546			2	2	|	|	|	|	520	5.5												
	1547			|	2½	|	|	|	|	520	[illegible]												
	1548			|	3	|	|	|	|	[illegible]	|												
	1549			|	3½	|	|	|	|	520	|												
	1550			↓	4	|	|	|	|	520	↓												
	1551			STA	CK	|	|	|	|	525	[illegible]												
	1553			3	2	|	|	|	|	525	6.2												
	1554			|	2½	|	|	|	|	520	5.8												
	1555			|	3	|	|	|	|	520	5.8												
	1556			|	3½	|	|	|	|	525	5.7												
	1557			↓	4	↓	↓	↓	↓	525	5.6	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{H_2}{NH_3}$
2-4-77	1552	NAT	GAS	STACK		395	—	—	—	540	5.85	—	8.7	—	—	—	—	—	—	—	—	—	—
5 INJECTORS	1559			STACK						530	↓		↓										
NO BIAS.	1600			1	2					4?0	[illegible]		8.3										
AT INJECTOR	1601				2½					470	[illegible]												
	[illegible]				3					470	[illegible]		↓										
	1603				3½					[illegible]	6.2		8.5										
	1604			↓	4					490	5.5		8.7										
	1605			STACK						5?0	5.6												
	1606			S	2					470	6.3		8.3										
	1607				2½					4?0	6.5		8.7										
	1608				3					4?0	6.2												
	1609				3½					500	5.6												
	1610				4					500	5.8												
	1611			↓	0	↓	↓	↓	↓	510	5.9	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓
2-8-77	[illegible]	NAT	GAS	1615		366	.181	0	0	515	5.3	—	9.1	0.8	—	—	0	-	—	—	0	1.0	0
	1635						.182	0		520				—							0	1.0	
	[illegible]							.9		[illegible]				1352							4.9	.461	
	1705			↓		↓	↓	0	↓	5?0	↓	↓	↓	—	↓	↓	↓	↓	↓	↓	0	1.0	↓
2-9-77	1415	NAT	GAS	1615		352	.184	0	0	525	5.4	—	9.1	—	—	—	—	—	—	—	0	1.0	0
	1420							.0925		300	5.4			39.8							5	.571	
	1432						.193	0		550	5.4			—							0	1.0	
	1455						.176	0		500	5.5			—							0	1.0	
	1459							.204		220	5.4			209							1.16	.44	
	1510						.158	0		450	5.4			—							0	1.0	
	1525						.153	0		520	5.4			—							0	1.0	
	1530							.45		130	5.4			721							2.46	.288	
	1550						↓	0		515	5.1			—							0	1.0	
	1600						.184	0		525	5.4			—							0	1.0	
	1610						↓	1.085		55	5.4			1953							6.0	.105	
	1625			↓		↓	.181	0	↓	515	5.3	↓	↓	-	↓	↓	↓	↓	↓	↓	0	1.0	↓

KVB

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{N_2}{NH_3}$
2-10-77	1255	NAT	GAS	1725		386	.183	0	0	520	4.9	–	9.3	–	–	–	0	–	—	–	0	1.0	0
	1300							.0925		340	5.0			50					310		.50	.65	
	1312							0		520				–					–		0	1.0	
	1320						↓	.204		230				209					235		1.11	.44	
	1335						.175	0		560				–					–		0	1.0	
	1336							0		500				—					–		0	1.0	
	1345							.46		120				625					110		2.62	.24	
	1355						↓	0		515	↓			—					–		0	1.0	
	1400						.185	0		525	5.1			–					–		0	1.0	
	1405							.96		75				1745					56		5.2	.142	
	1450							0		525				–					–		0	1.0	
	1455			↓			↓	.0925		330				86					325		.50	.63	
	1503			1825			.196	0		560				–					–		0	1.0	
	1510						↓	.0925		320	↓			–					325		.47	.57	
	1525						.184	0		525	5.0			–					–		0	1.0	
	1535						↓	.216		130	↓			34					150		1.17	.248	
	1555						.196	0		545	5.0			-					–		0	1.0	
	1600						.179	0		510	5.15			–					–		0	1.0	
	1613							.476		53	5.0			101					72		2.65	.104	
	1615							0		510	5.1			–					–		0	1.0	
	1620						↓	1.26		18	5.0			457					22		7.0	.035	
	1625			↓		↓	.184	0	↓	525	↓	↓	↓	–	↓	↓	↓	↓	–	↓	0	1.0	↓
2-11-77	1420			1725		386	.176	0	0	500	5.0	–	9.3	-	–	–	0	–	–	–	0	1.0	0
	1425							.0925		310	4.9			87							.52	.62	
	1450							0		505	5.1			–							0	1.0	
	1455							—		210	↓			–							—	—	
	1527							0		500	5.2			—							0	1.0	
	1533							.219		190	↓			304							1.24	.35	
	1550						↓	0		505	5.3			–							0	1.0	
	1552						.181	.456		110	5.25			764							2.68	.218	
	1615							0		515	↓			-							0	1.0	
	1620							1.275		55	5.2			2577							7.05	.106	
	1643			↓		↓	↓	0	↓	515	↓	↓	↓	—	↓	↓	↓	↓	↓	↓	0	1.0	↓

KVB

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{H_2}{NH_3}$
2-15-77	1135	NAT	GAS	1880		387	.0327	0	0	94	5.1	–	9.3	8.8	<1	–	0	–	–	–	0	1.0	0
	1210						.180	0		510	5.0			–	–						0	1.0	
	1220							.095		285	4.9			13	<1				280		.55	.53	
	1235						↓	0		515	5.1			–	–				–		0	1.0	
	1255						.177	.219		120	4.9			80	<1				–		1.23	.24	
	1305						.182	0		515	5.0			–	–				–		0	1.0	
	1310						↓	.48		49	4.9			400	<1				46		2.64	.078	
	1325						.183	0		520	5.0			–	–				–		0	1.0	
	1335						↓	1.07		20	4.9			1559	<1				22		5.55	.038	
	1350			↓		↓	.189	0	↓	540	4.9	↓	↓	–	–	↓	↓	↓	–	↓	0	1.0	↓
2-16-77	1050	NAT	GAS	1825		387	.0331	0	0	94	4.8	–	9.3	–	<1	–	0	–	–	–	0	1.0	0
	1112						.180	0		510					–				–		0	1.0	
	1120							.0925		270					<1				–		.52	.53	
	1130							0		510					–				–		0	1.0	
	1135							.218		150					<1				147		1.21	.29	
	1150							0		510					–				–		0	1.0	
	1200							.47		55					<1				59		2.6	.108	
	1207							0		510					–				–		0	1.0	
	1215							.98		19					<1				22		5.4	.037	
	1225			↓		↓	↓	0	↓	510	↓	↓	↓	↓	–		↓	↓	–	↓	0	1.0	↓
	1235			1720		387	.176	0	0	500	4.8	–	9.3	–	–		0	–	–	–	0	1.0	0
	1245							.0925		340					<1				–		.52	.68	
	1255							0		500					–				–		0	1.0	
	1300						↓	.217		210					<1				200		1.22	.48	
	1312						.12	0		510					–				–		0	1.0	
	1315							.45		162					<1				140		2.5	.32	
	1330							0		510					–				–		0	1.0	
	1345							.97		95					<1				78		5.4	.185	
	1355			↓		↓	↓	0	↓	520	↓	↓	↓	↓	–	↓	↓	↓	–	↓	0	1.0	↓

KVB

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_2 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios NH_3/NO_o	NO/NO_o	N_2/NH_3
2-17-77	0935	NAT	GAS	1615		390	.186	0	0	525	5.7	—	9.1	—	<1	—	0	525	525	-	0	1.0	0
	1004						↓	0		[illegible]	5.6				<1			—	—		0	1.0	
	1012						.184	0		[illegible]	5.7				—			—	—		0	1.0	
	1016						↓	[illegible]		[illegible]	5.7				<1			—	[illegible]		.52	[illegible]	
	1030						.175	0		[illegible]	5.6							-			[illegible]	1.0	
	1040						.182	0		[illegible]	5.7				—			—	—		0	1.0	
	1053						↓	[illegible]		[illegible]	5.7				<1			410	410		.52	.76	
	1116						.181	0		510	5.7				-			—	—		0	1.0	
	1124						[illegible]	0		520	5.7							-	—		0	1.0	
	1127						↓	.21		[illegible]	5.7				<1			350	270		1.16	.77	
	1137						.191	0		[illegible]	5.7				—			—	—		0	1.0	
	1142							0		510	5.7				—			—	—		0	1.0	
	1142						↓	.44		[illegible]	5.7				<1			230	245		2.34	.61	
	1200						.177	0		[illegible]	5.7				—			—	—		0	1.0	
	1206							[illegible]		[illegible]	5.7				<1			162	167		5.5	.37	
	1216			↓		↓	↓	0	↓		5.7	↓	↓	↓	—	↓	↓	—	—	↓	0	1.0	↓
2-22-77	1310	NAT	GAS	1720		396	.176	0	0	500	5.1	25	9.3	—	—	9	0	445	445	—	0	1.0	0
	1340						.174	0		495	5.0	25				44		410	445		0	1.0	
	1356							[illegible]		150	4.8	30				113		130	127		2.57	.302	
	1420									155	4.9	30				156		126	125			.313	
	1435						↓	↓		155	5.0	[illegible]				2.1		127	125		↓	.33	
	1445			↓		↓	.183	0	↓	550	5.1	25	↓	↓	↓	-	↓	460	450	↓	0	1.0	↓

KVB

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	[illegible] ppm	Wet SO_2 ppm	NO ppm	NO_x ppm	UHC ppm	Molar Ratios NH_3/NO_i	NO/NO_i	H_2/[illegible]
3-8-77	1200	UTAH	COAL	1715		378	0.298	0	0	775	5.0	65	15.0	—	—	—	355	—	—	8	0	1.0	—
	1219					392	0.298	0.176	0	326	5.1	65	14.4	—	—	—	352	—	—	9	0.591	0.465	—
	1225					392	0.298	0.377	0	200	5.1	80	14.4	—	—	—	353	—	—	9	1.26	0.26	—
	1232					392	0.298	0.775	0	80	5.0	—	—	—	—	—	—	—	—	9	2.59	0.104	—
	1238					392	[illegible]	2.01	0	16	4.9	118	14.7	—	—	—	0	—	—	9	6.75	0.021	—
	1310					392	0.296	0	0	260	5.1	65	14.7	—	—	—	272	—	—	9	0	1.0	—
	1315					392	0.296	0.176	0	340	5.0	75	14.4	—	—	—	276	—	—	—	0.591	[illegible]	—
	1338					392	[illegible]	0.375	0	158	4.7	85	15.0	—	—	—	292	—	—	—	1.27	[illegible]	—
	1402					392	0.296	0.781	0	56	4.5	95	14.7	—	—	—	322	—	—	—	[illegible]	[illegible]	—
	1416					[illegible]	0.296	2.01	0	14	4.9	100	14.7	—	—	—	0	—	—	—	6.8	[illegible]	—
	1322			1715		398	0.296	0.176	0	336	4.9	65	14.4	—	—	—	290	—	—	—	0.591	0.512	—
	1342					[illegible]	0.296	0.375	0	220	4.8	75	15.0	—	—	—	287	—	—	—	1.27	[illegible]	—
	1403					392	0.296	0.781	0	66	4.8	85	14.4	—	—	—	193	—	—	—	2.64	[illegible]	—
	1419					392	[illegible]	2.01	0	11	4.8	105	14.7	—	—	—	0	—	—	—	6.8	[illegible]	—
	1322			1775		391	[illegible]	0.176	0	516	4.7	65	14.7	—	—	—	322	—	—	—	0.591	[illegible]	—
	1348					392	[illegible]	0.375	0	[illegible]	4.7	[illegible]	[illegible]	—	—	—	[illegible]	—	—	—	1.27	[illegible]	—
	1406					392	[illegible]	0.781	0	[illegible]	4.8	[illegible]	14.7	—	—	—	212	—	—	—	[illegible]	[illegible]	—
	1422					392	[illegible]	[illegible]	0	[illegible]	4.7	[illegible]	14.4	—	—	—	0	—	—	—	[illegible]	[illegible]	—
	1322			1835		392	[illegible]	0.176	0	[illegible]	5.0	65	14.7	—	—	—	[illegible]	—	—	—	[illegible]	[illegible]	—
	1350					[illegible]	[illegible]	[illegible]	0	520	4.6	55	[illegible]	—	—	—	[illegible]	—	—	—	[illegible]	[illegible]	—
	1409					392	0.296	0.781	0	[illegible]	4.7	65	14.7	—	—	—	215	—	—	—	2.64	[illegible]	—
	1425					[illegible]	0.296	2.01	0	135	4.8	70	14.7	—	—	—	0	—	—	—	6.8	[illegible]	—
	1330			[illegible]		[illegible]	0.296	0.176	0	[illegible]	4.9	[illegible]	14.9	—	—	—	[illegible]	—	—	—	0.591	0.84	—
	1352					392	[illegible]	0.375	0	[illegible]	4.8	55	14.7	—	—	—	301	—	—	—	1.27	[illegible]	—
	1411					392	0.296	0.781	0	[illegible]	4.9	55	15.0	—	—	—	247	—	—	—	[illegible]	0.63	—
	[illegible]					[illegible]	[illegible]	2.01	0	[illegible]	[illegible]	[illegible]	[illegible]	—	—	—	0	—	—	—	6.8	[illegible]	—
	1334			1750		392	0.296	0.176	0	[illegible]	4.7	[illegible]	14.4	—	—	—	310	—	—	—	0.591	[illegible]	—
	1354					[illegible]	[illegible]	0.375	0	[illegible]	4.8	55	14.7	—	—	—	325	—	—	—	1.27	0.54	—
	1415					[illegible]	0.296	0.781	0	[illegible]	4.8	58	14.7	—	—	—	212	—	—	—	2.64	[illegible]	—
	1431					392	0.296	2.01	0	450	4.6	55	14.7	—	—	—	0	—	—	—	6.8	[illegible]	—
	1432			1750		392	[illegible]	0.372	0	130	4.8	70	14.7	—	—	—	0	—	—	—	1.26	[illegible]	—
	1435					[illegible]	[illegible]	0.192	0	[illegible]	5.0	75	14.4	—	—	—	0	—	—	—	1.32	0.25	—
	1437					[illegible]	[illegible]	[illegible]	0	[illegible]	5.0	[illegible]	14.4	—	—	—	0	—	—	—	2.36	[illegible]	—
	1443					392	[illegible]	0.715	0	110	5.2	60	14.4	—	—	—	0	—	—	—	2.42	0.195	—
	1445					392	[illegible]	0.159	0	128	[illegible]	[illegible]	[illegible]	—	—	—	0	—	—	—	2.25	0.155	—

Test Date	Time	Primary		Controlled		Flow Rates (scfm)				Stack Emissions											Molar Ratios		
										Dry							Wet						
		Fuel	Type	Gas	Temp	V_{Air}	[illegible]	V_{NH_3}	V_{H_2}	NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	[illegible] ppm	SO_2 ppm	NO ppm	NO_x ppm	UHC ppm	NH_3/NO_o	NO/NO_o	H_2/NH_3
3-18-77	1045	UTAH	[illegible]	—		409	0.317	0	0	760	5.2	55	14.4	3.2	5.3	<1	345	650	690	1	0	1.0	—
	1130			—		409	0.296	0	0	715	4.9	60	14.4	—	—	—	—	—	—	—	0	1.0	—
	1150			1850		409	0.296	0.155	0	595	4.9	55	14.4	1.7	8.12	<1	350	463	463	NA	2.515	0.75	—
	1215			[illegible]		409	0.296	0.143	0	415	4.8	70	15.5	1.6	13.15	<1	355	315	330	NA	1.16	0.615	—
	1245			1900		409	0.29	0.581	0	390	4.8	65	14.7	29	14.75	<1	365	210	225	NA	1.97	0.527	—
	1325			[illegible]		409	0.296	0.87	0	340	4.9	65	14.7	1435	18.7	<1	350	140	145	NA	3.0	0.46	—
	1350			—		409	0.313	0	0	745	4.9	65	14.7	—	—	—	335	760	720	NA	0	1.0	—
	1425			1940		409	[illegible]	0.31	0	[illegible]	4.9	65	14.9	27.5	11.75	<1	344	250	255	NA	2.94	0.575	—
	1435			[illegible]		409	[illegible]	0.20	0	[illegible]	5.0	70	14.7	2.4	9.65	<1	377	390	395	NA	1.95	0.506	—
	1450					409	[illegible]	0.393	0	620	5.2	45	14.7	6.9	7.15	<1	340	470	490	NA	1.15	0.61	—
	1520					409	[illegible]	0.152	0	680	[illegible]	45	14.7	8.5	7.4	<1	346	595	610	NA	0.505	0.89	—
	1550			—		409	0.317	0	0	750	5.2	45	14.7	—	—	—	348	735	765	NA	0	1.0	—
	1615			—		409	0.319	0	0	785	5.2	45	14.7	—	—	—	340	730	765	NA	0	1.0	—
3-21-77	1315	UTAH	[illegible]			[illegible]	0.344	0	0	710	4.8	60	14.7	4.7	<1	<1	340	710	790	6	0	1.0	—
	1400			—		391	0.300	0	0	720	4.7	70	14.7	—	—	—	370	—	—	—	0	1.0	—
	1415			1700		[illegible]	[illegible]	[illegible]	0	210	4.5	55	14.4	175.9	1.99	<1	330	160	170	5	1.14	0.27	—
	1440			1700		[illegible]	0.377	[illegible]	0	60	4.5	70	14.4	1018	2.75	<1	315	44	44	6	2.93	0.071	—
	1515			—		391	0.294	0	0	750	4.8	50	14.4	—	—	—	61	—	—	10	0	1.0	—
	1530			1710		[illegible]	[illegible]	0.885	0	54	4.8	75	14.4	799	2.86	<1	9	19	19	9	3.0	0.071	—
	1555			1710		391	0.29	0.417	0	270	4.5	65	14.4	167.3	1.75	<1	86	—	—	11	1.17	0.355	—
	1610			—		[illegible]	[illegible]	0	0	700	4.8	60	14.4	—	—	—	173	700	720	7	0	1.0	—
3-23-77	1350	UTAH	[illegible]	—		397	0.27	0	0	765	5.2	45	14.4	7.3	—	—	325	610	720	—	0	1.0	—
	1535			—		397	0.31	0	0	800	5.0	45	14.4	11.2	—	—	344	—	—	—	0	1.0	—
3-24-77	1010	UTAH	[illegible]	—		397	0.313	0	0	810	5.0	55	14.4	—	—	—	363	—	—	—	0	1.0	—
	1035			1725		397	0.313	0.348	0	170	5.1	80	14.4	126	—	—	354	160	166	11	1.1	0.24	—
	1145			1755		397	0.29	0.348	0	155	4.8	75	14.4	77	—	—	345	145	153	10	1.15	0.24	—
	1230			—		397	0.29	0	0	775	4.9	45	14.4	—	—	—	348	720	750	11	0	1.0	—
	1255			1710		397	[illegible]	0.348	0	270	4.9	70	14.7	55	—	—	—	—	—	—	1.15	0.364	—
	1350			—		397	0.31	0	0	800	5.5	50	14.4	—	—	—	353	725	745	10	0	1.0	—

Test Date	Time	Primary Fuel	Primary Type	Combustion Gas	Combustion Temp	Flow Rates (scfm) $\dot{V}_{Air}$	$\dot{V}_{NO}$	$\dot{V}_{NH_3}$	$\dot{V}_{H_2}$	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	SO_3 ppm	Wet SO_2 ppm	NO ppm	NO_x ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{H_2}{NH_3}$
3-29-77	1130	[illegible]	[illegible]	—		[illegible]	[illegible]	0	—	[illegible]	5.4	[illegible]	14.4	—	0.79	<1	—	625	650	—	0	1.0	—
	[illegible]			—		[illegible]	[illegible]	0	—	[illegible]	5.4	[illegible]	14.7	3.0	—	—	333	—	—	11	0	1.0	—
	[illegible]			—		[illegible]	[illegible]	0	—	[illegible]	5.4	75	14.4	—	—	—	345	—	—	—	0	1.0	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.4	[illegible]	14.7	225	[illegible]	<1	[illegible]	420	440	10	0.528	0.675	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]	14.7	422	23	<1	[illegible]	210	[illegible]	11	1.65	0.55	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]	14.7	513	8.3	<1	133	150	155	10	2.68	0.346	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]	14.7	—	—	—	[illegible]	175	175	10	2.68	0.346	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.2	[illegible]	14.7	1300	12.2	<1	0	100	100	7	2.96	0.233	—
	[illegible]			—		[illegible]	[illegible]	0	—	[illegible]	[illegible]	76	14.7	—	—	—	0	[illegible]	[illegible]	7	0	1.0	—
5-3-77	[illegible]	[illegible]	[illegible]	—		[illegible]	[illegible]	0	—	[illegible]	5.5	50	14.8	—	—	—	460	—	—	—	0	1.5	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	445	—	—	—	0.529	0.67	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.4	50	14.8	—	—	—	460	—	—	—	0.525	0.727	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.4	50	14.8	—	—	—	445	—	—	—	0.515	0.758	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	458	—	—	—	[illegible]	0.51	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]	50	[illegible]	—	—	—	455	—	—	—	0.525	0.57	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	445	—	—	—	1.59	0.723	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	56	[illegible]	—	—	—	[illegible]	—	—	—	1.59	0.712	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	56	14.8	—	—	—	[illegible]	—	—	—	1.59	0.622	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]	[illegible]	—	—	—	430	—	—	—	1.59	0.524	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	420	—	—	—	1.59	0.471	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.6	50	14.8	—	—	—	420	—	—	—	1.79	[illegible]	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.6	[illegible]	14.8	—	—	—	411	—	—	—	1.79	0.273	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	420	—	—	—	1.79	0.36	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	[illegible]	—	—	—	1.79	0.51	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.6	50	14.8	—	—	—	[illegible]	—	—	—	1.79	0.62	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]	50	14.8	—	—	—	405	—	—	—	2.73	0.495	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]	50	14.8	—	—	—	410	—	—	—	2.73	0.355	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	190	5.5	50	14.8	—	—	—	385	—	—	—	2.73	0.224	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	380	—	—	—	2.73	0.136	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.5	50	14.8	—	—	—	390	—	—	—	2.73	0.111	—
	[illegible]			—		[illegible]	[illegible]	[illegible]	—	[illegible]	5.4	50	14.8	—	—	—	397	—	—	—	0	1.0	—

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KVB

Test Date	Time	Primary Fuel	Primary Type	[illegible] Gas	[illegible] Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet NO_x ppm	NO ppm	NH_3 ppm	UNC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{H_2}{NH_3}$
5-5-77	1535	[illegible]	[illegible]	—		[illegible]	0.38	0.152	—	722	5.5	50	14.6	—	—	—	523	—	—	—	0	1.0	—
	[illegible]			1180		[illegible]	0.32	0.152	—	430	5.5	50	14.0	—	—	—	311	—	—	—	0.543	0.592	—
	1540			[illegible]		[illegible]	0.32	0.152	—	355	5.4	50	[illegible]	—	—	—	312	—	—	—	0.543	0.494	—
	[illegible]			[illegible]		[illegible]	[illegible]	0.152	—	360	5.4	50	[illegible]	—	—	—	312	—	—	—	0.543	0.5	—
	[illegible]			[illegible]		[illegible]	[illegible]	0.152	—	400	5.5	50	[illegible]	—	—	—	312	—	—	—	0.543	0.555	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	415	5.5	50	14.0	—	—	—	[illegible]	—	—	—	0.543	0.637	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]		535	5.4	50	[illegible]	—	—	—	316	—	—	—	0.543	0.735	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	290	[illegible]	50	14.0	—	—	—	[illegible]	—	—	—	1.2	0.53	—
	[illegible]					[illegible]	[illegible]	[illegible]	—	180	5.4	50	14.0	—	—	—	[illegible]	—	—	—	1.2	0.39	—
	[illegible]					[illegible]	[illegible]	0.152	—	195	5.4	50	14.3	—	—	—	317	—	—	—	1.2	0.271	—
	[illegible]			[illegible]		[illegible]	[illegible]	0.152	—	163	5.4	50	14.3	—	—	—	[illegible]	—	—	—	1.2	0.223	—
	[illegible]			[illegible]		[illegible]	[illegible]	0.152	—	170	5.4	[illegible]	14.3	—	—	—	[illegible]	—	—	—	1.2	0.237	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	205	5.4	[illegible]	[illegible]	—	—	—	[illegible]	—	—	—	1.2	0.33	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	160	5.4	[illegible]	14.2	—	—	—	[illegible]	—	—	—	1.98	0.224	—
	[illegible]					[illegible]	[illegible]	[illegible]	—	[illegible]	5.4	50	14.3	—	—	—	[illegible]	—	—	—	1.98	0.111	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	72	5.4	50	14.3	—	—	—	[illegible]	—	—	—	1.98	0.1	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	90	5.4	50	14.3	—	—	—	[illegible]	—	—	—	1.98	0.125	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	130	5.4	50	14.3	—	—	—	[illegible]	—	—	—	1.98	0.237	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	280	5.4	50	14.2	—	—	—	316	—	—	—	1.98	0.39	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	150	5.4	50	[illegible]	—	—	—	[illegible]	—	—	—	3.01	0.269	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	94	5.4	50	[illegible]	—	—	—	312	—	—	—	3.01	0.163	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.4	50	[illegible]	—	—	—	312	—	—	—	3.01	0.061	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	45	5.4	50	[illegible]	—	—	—	[illegible]	—	—	—	3.01	[illegible]	—
	[illegible]					[illegible]	[illegible]	[illegible]	—	55	5.4	50	14.2	—	—	—	[illegible]	—	—	—	3.01	0.077	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	—	110	5.4	50	[illegible]	—	—	—	287	—	—	—	3.01	0.153	—
5-12-77	1158	[illegible]	[illegible]	—		[illegible]	[illegible]	0	—	750	5.2	50	14.4	—	—	—	—	—	—	—	0	1.0	—
	1210			1680		[illegible]	[illegible]	0.162	—	450	5.3	50	14.4	—	—	—	—	—	—	—	0.569	0.665	—
	1212			1725		[illegible]	[illegible]	0.162	—	475	5.3	50	14.4	—	—	—	—	—	—	—	1.19	0.582	—
	1215			1770		[illegible]	[illegible]	0.162	—	[illegible]	5.2	50	14.4	—	—	—	—	—	—	—	1.19	0.662	—
	1217			1810		[illegible]	[illegible]	0.162	—	575	5.1	50	14.4	—	—	—	—	—	—	—	1.19	0.772	—
	1219			1860		[illegible]	[illegible]	0.162	—	610	5.2	50	14.4		—	—		—	—	—	1.19	0.525	—
	1221			1910		[illegible]	[illegible]	0.162	—	650	5.2	50	14.4	—	—	—	—	—	—	—	1.19	0.852	—
	1225			1915		[illegible]	0.285	0.417	—	520	5.0	50	14.4	—	—	—	—	—	—	—	1.19	0.765	—
	1227			1670		[illegible]	[illegible]	[illegible]	—	450	5.1	50	14.4	—	—	—	—	—	—	—	1.19	0.609	—
	1229			1725		[illegible]	0.285	0.417	—	370	5.1	50	14.4		—	—	—	—	—	—	1.19	0.5	—
	1231			1780		[illegible]	0.285	0.417	—	240	5.1	50	14.4	—	—	—	—	—	—	—	1.19	0.324	—

CONT'D

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KVB

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) V_{Air}	V_{NO}	V_{NH_3}	V_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{N_2}{NH_3}$
5-12-77	1233	VTAN	TORA.0	1725		3940	0.285	0.337	0	190	5.2	50	14.4	—	—	—	—	—	—	—	1.19	0.257	—
	1235			1695		3940	0.285	0.337	0	210	5.2	50	14.4	—	—	—	—	—	—	—	1.19	0.285	—
	1237			1675		3940	0.285	0.558	0	160	5.2	50	14.4	—	—	—	—	—	—	—	1.96	0.216	—
	1239			1745		3940	0.285	0.558	0	130	5.1	50	14.4	—	—	—	—	—	—	—	1.96	0.176	—
	1241			1760		3940	0.285	0.558	0	145	5.1	50	14.4	—	—	—	—	—	—	—	1.96	0.187	—
	1243			1725		3940	0.285	0.558	0	230	5.1	50	14.4	—	—	—	—	—	—	—	1.96	0.311	—
	1245			1875		3940	0.285	0.558	0	350	5.1	50	14.4	—	—	—	—	—	—	—	1.96	0.473	—
	1247			1915		3940	0.285	0.558	0	450	5.1	50	14.4	—	—	—	—	—	—	—	1.96	0.609	—
	1250			1925		3940	0.285	0.882	0	355	4.9	50	14.4	—	—	—	—	—	—	—	3.1	0.479	—
	1252			1845		3940	0.285	0.882	0	210	5.0	50	14.4	—	—	—	—	—	—	—	3.1	0.284	—
	1254			1845		3940	0.29	0.882	0	145	5.0	50	14.4	—	—	—	—	—	—	—	3.1	0.187	—
	1256			1775		3940	0.285	0.882	0	35	5.0	50	14.4	—	—	—	—	—	—	—	3.1	0.051	—
	1258			1740		3940	0.285	0.882	0	55	4.9	50	14.4	—	—	—	—	—	—	—	3.1	0.075	—
	1300			1700		3940	0.285	0.882	0	115	4.9	50	14.4	—	—	—	—	—	—	—	3.1	0.149	—
	1515			1570		3940	0.216	0.155	0	310	5.4	55	14.4	—	—	—	—	—	—	—	0.72	0.52	—
	1517			1725		3940	0.216	0.155	0	315	5.6	60	14.4	—	—	—	—	—	—	—	0.72	0.445	—
	1519			1750		3940	0.216	0.155	0	320	5.5	[illegible]	14.4	—	—	—	—	—	—	—	0.72	0.475	—
	1521			1710		3940	0.216	0.155	0	330	5.5	[illegible]	14.4	—	—	—	—	—	—	—	0.72	0.410	—
	1523			1785		3940	0.216	0.155	0	385	5.5	[illegible]	14.4	—	—	—	—	—	—	—	0.72	0.562	—
	1525			1755		3940	0.216	0.155	0	480	5.4	60	14.4	—	—	—	—	—	—	—	0.72	0.593	—
	1527			1655		3940	0.216	0.254	0	290	5.4	60	14.4	—	—	—	—	—	—	—	1.18	0.415	—
	1529			1760		3940	0.216	0.254	0	430	5.5	[illegible]	14.4	—	—	—	—	—	—	—	1.18	0.41	—
	1531			1730		3940	0.216	0.254	0	220	5.4	[illegible]	14.4	—	—	—	—	—	—	—	1.18	0.327	—
	1533			1765		3940	0.216	0.254	0	230	5.4	65	14.4	—	—	—	—	—	—	—	1.18	0.341	—
	1535			2010		3940	0.216	0.254	0	250	5.4	65	14.4	—	—	—	—	—	—	—	1.18	0.57	—
	1537			1790		3940	0.216	0.254	0	410	5.4	[illegible]	14.4								1.18	0.450	—
	1541			1615		3940	0.216	0.437	0	240	5.5	65	14.4		—	—					2.03	0.355	—
	1543			[illegible]		3940	0.216	0.437	0	[illegible]	5.5	60	14.4	—	—						2.03	0.237	—
	1545			1760		3940	[illegible]	0.437	0	130	5.5	60	14.4			—					2.03	0.193	—
	1547			1750		3940	0.216	0.437	0	130	5.5	60	14.4	—		—					2.03	0.193	—
	1549			1750		3940	0.216	0.437	0	145	5.6	60	14.4	—	—	—	—	—	—	—	2.03	0.215	—
	1551			1745		3940	0.216	0.437	0	170	5.5	60	14.4	—	—	—	—	—	—	—	2.03	0.252	—
	1555			[illegible]		3940	0.216	0.656	0	120	5.4	[illegible]	14.4	—	—	—	—	—	—	—	3.05	0.178	—
	1557			1790		3940	0.216	0.656	0	95	5.6	60	14.4	—	—	—	—	—	—	—	3.05	0.111	—
	1559			1755		3940	0.216	0.656	0	75	5.6	[illegible]	14.4	—	—	—	—	—	—	—	3.05	0.111	—
	1601			[illegible]		3940	0.216	0.656	0	85	5.7	[illegible]	14.4	—	—	—	—	—	—	—	[illegible]	0.124	—
	1603					3940	0.216	0.656	0	120	5.6	60	14.4	—	—	—	—	—	—	—	3.05	0.178	—
	1605			1720		3940	0.216	0.656	0	170	5.5	[illegible]	14.4	—	—	—	—	—	—	—	3.05	0.252	—

Test Date	Time	Primary Fuel	Primary Type	Controlling Gas	Controlling Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	SO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UNC ppm	Molar Ratios NH_3/NO_0	NO/NO_0	H_2/NH_3
3-31-77	1135	[illegible]	[illegible]	—		372	0.257	0	0	530	5.4	105	14.4	8.2	1.6	7.5	[illegible]	515	555	2	0	1.0	—
	1205			[illegible]		372	0.257	[illegible]	0	425	5.7	121	14.4	215	2.5	8.1	[illegible]	[illegible]	[illegible]	1	[illegible]	[illegible]	—
	1232			[illegible]		372	[illegible]	[illegible]	0	[illegible]	5.2	[illegible]	14.4	188	3.6	6.0	[illegible]	212	[illegible]	1	0.705	0.51	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	0	175	5.7	[illegible]	14.4	241	2.7	7.9	360	155	170	2	1.56	[illegible]	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	0	212	5.5	[illegible]	14.4	[illegible]	2.6	21.4	[illegible]	140	155	2	1.22	[illegible]	—
4-4-77	[illegible]	[illegible]	[illegible]	—		377	[illegible]	0	0	[illegible]	[illegible]	75	14.4	8.7	2.8	5.4	[illegible]	[illegible]	[illegible]	15	0	1.0	—
	1150			1775		377	[illegible]	[illegible]	0	[illegible]	[illegible]	76	14.4	2.2	[illegible]	5.5	[illegible]	240	[illegible]	10	[illegible]	0.7	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	0	[illegible]	5.1	75	14.7	18	1.2	[illegible]	[illegible]	[illegible]	175	[illegible]	[illegible]	0.48	—
	1312					[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]	65	14.7	32	0.7	5.4	[illegible]	135	155	9	.14	[illegible]	—
	1342			[illegible]		[illegible]	[illegible]	[illegible]	0	140	[illegible]	[illegible]	14.7	[illegible]	2.3	7.2	[illegible]	67	72	9	1.54	[illegible]	—
4-5-77	1057	[illegible]	[illegible]	—		362	0.22	0	0	[illegible]	5.3	75	14.4	2.2	[illegible]	5.6	470	[illegible]	610	9	0	1.0	—
	[illegible]			—		[illegible]	[illegible]	0	0	[illegible]	[illegible]	[illegible]	[illegible]	—	—	—	[illegible]	—	—	—	0	1.0	—
	[illegible]			[illegible]		372	[illegible]	0.1	0	[illegible]	5.2	65	14.4	5.5	[illegible]	[illegible]	[illegible]	[illegible]	355	10	[illegible]	[illegible]	—
	215			[illegible]		[illegible]	[illegible]	[illegible]	0	[illegible]	5.2	95	14.4	11	0.2	7.5	[illegible]	[illegible]	152	11	1.04	[illegible]	—
	[illegible]			[illegible]		375	[illegible]	[illegible]	0	170	5.3	[illegible]	[illegible]	51	1.6	7.2	[illegible]	[illegible]	155	12	[illegible]	[illegible]	—
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	0	[illegible]	5.1	85	14.4	176	2.5	9.0	[illegible]	[illegible]	147	5	1.5	[illegible]	—
	[illegible]			—		[illegible]	[illegible]	0	0	[illegible]	4.9	50	14.4	—	—	—	[illegible]	[illegible]	[illegible]	5	0	1.0	—
4-6-77	[illegible]	[illegible]	[illegible]	—		362	0.312	0	—	[illegible]	5.3	65	14.4	3.4	—	—	470	510	600	7	0	1.0	—
	[illegible]			—		[illegible]	[illegible]	0	—	[illegible]	5.4	55	14.4	[illegible]	—	—	[illegible]	[illegible]	[illegible]	10	0	1.0	—
	[illegible]			[illegible]		[illegible]	[illegible]	0	—	[illegible]	5.2	[illegible]	14.4	—	—	—	[illegible]	—	—	—	0	1.0	—
	1415			[illegible]		[illegible]	[illegible]	[illegible]	—	[illegible]	5.1	72	14.4	32	—	—	[illegible]	125	155	6	1.04	0.314	—
	[illegible]			1775		[illegible]	[illegible]	[illegible]	—	[illegible]	5.1	72	14.4	95	—	—	445	140	165	10	1.04	[illegible]	—
	[illegible]			—		[illegible]	[illegible]	0	—	[illegible]	5.0	45	14.4	—	—	—	460	—	—	—	0	1.0	—
4-11-77	1135	[illegible]	[illegible]	—		367	[illegible]	0	—	[illegible]	[illegible]	[illegible]	14.7	4.0	0.28	6.5	[illegible]	—	—	—	0	1.0	—
	[illegible]			—		367	[illegible]	0	—	[illegible]	5.2	45	14.7	—	—	—	[illegible]	—	—	—	0	1.0	—
	[illegible]			[illegible]		367	0.261	0.186	—	[illegible]	5.2	45	14.7	5.6	0.2	6.5	[illegible]	—	—	11	[illegible]	[illegible]	—
	[illegible]					367	0.254	0	—	[illegible]	[illegible]	45	14.7	—	—	—	[illegible]	—	—	—	0	1.0	—
	[illegible]			[illegible]		367	0.254	[illegible]	—	[illegible]	5.2	70	14.7	5.1	0.12	7.5	[illegible]	—	—	11	[illegible]	0.55	—
	[illegible]			[illegible]		367	0.254	[illegible]	—	[illegible]	5.4	[illegible]	14.7	7.2	[illegible]	5.9	[illegible]	210	260	10	1.28	0.405	—
	325			[illegible]		367	[illegible]	[illegible]	—	[illegible]	[illegible]	55	14.7	13	0.69	7.7	560	210	200	9	1.47	0.355	—
	[illegible]			—		367	0.254	0	—	[illegible]	[illegible]	[illegible]	14.7	—	—	—	580	670	720	16	0	1.0	—

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_o}$	$\frac{NO}{NO_o}$	$\frac{H_2}{NH_3}$
4-12-77	1105	[illegible]	[illegible]	–		386	0.279	0	0	740	5.5	65	14.7	4.3	0.3	7.9	550	—	—	—	0	1.0	—
	1130			–		390	0.27	0	0	710	5.2	150	14.7	—	—	—	—	—	—	—	0	1.0	—
	1205			[illegible]		390	0.29	0.132	0	700	5.2	45	14.7	3	0.15	6.8	463	500	600	6	0.472	0.92	—
	1230			[illegible]		[illegible]	0.29	0.132	0	650	5.2	[illegible]	14.7	—	—	—	457	—	—	—	0.472	0.86	—
	1245			[illegible]		[illegible]	0.29	0.247	0	620	5.2	45	14.7	3.1	0.13	6.3	480	465	470	6	0.842	0.79	—
	1310			[illegible]		390	0.29	0.247	0	550	5.0	45	14.7	—	—	—	558	—	—	—	0.842	0.76	—
	1315			[illegible]		[illegible]	0.29	0.364	0	550	5.0	46	14.7	4.1	0.11	6.7	540	340	400	6	1.26	0.725	—
	1340			[illegible]		390	0.29	0.364	0	[illegible]	5.1	45	14.7	—	—	—	530	—	—	—	1.26	0.725	—
	1355			[illegible]		391	0.27	[illegible]	0	[illegible]	5.1	43	14.7	7.1	0.05	7.6	[illegible]	420	450	6	1.49	0.79	—
	1435			—		390	0.310	0	0	516	4.7	46	14.7	—	—	—	544	—	—	—	0	1.0	—

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_o}$	$\frac{NO}{NO_o}$	$\frac{N_2}{NH_3}$
4-20-77	1025	ILL.	conc'c	1340		362	0.272	0	0	770	5.1	50	14.0	2.33	0.77	13.7	2380	*	785	4	0	1.0	—
	1045					362	0.275	0	0	750	5.1	50	14.0	—	—	—	—	—	—	—	0	1.0	—
	1110					362	0.275	0.136	0	540	5.0	50	14.0	3.12	1.8	12.6	3050	*	475	3	0.492	0.625	—
	1130					362	0.275	0.336	0	380	5.1	50	14.0	3.07	1.77	12.6	2970	*	350	3	1.24	0.49	—
	1200					362	0.275	0.273	0	470	5.1	50	[illegible]	1.71	0.95	12.7	3370	*	460	4	0.99	0.65	—
	1225					362	0.275	0.42	0	300	5.1	50	14.0	2.66	0.62	13.0	3140	*	225	3	1.53	0.385	—
	[illegible]			↓		362	0.272	0	0	770	5.2	50	14.0	—	—	—	2970	—	—	—	0	1.0	—
4-25-77	1045	ILL.	conc'c	[illegible]		368	0.268	0	0	780	5.0	50	14.4	2.73	4.03	12.9	3260	*	670	13	0	1.0	—
	1110					368	0.267	0	0	745	5.0	50	14.4	—	—	—	—	—	—	—	0	1.0	—
	1130					368	0.267	0.136	0	410	5.0	50	14.4	2.80	6.93	13.3	3200	*	375	12	0.505	0.55	—
	1150					368	0.267	0.273	0	275	5.1	50	14.4	11.9	2.65	13.1	3250	*	245	10	1.02	0.39	—
	1215					368	0.267	0.336	0	240	5.1	50	14.7	49.9	0.79	12.7	3220	*	190	12	1.26	0.322	—
	1245			↓		368	0.267	0.42	0	200	5.1	50	14.4	112	0.49	16.2	2950	*	130	12	1.57	0.269	—
	[illegible]			[illegible]		368	0.267	0.42	0	400	5.1	50	14.4	—	—	—	2730	—	—	—	1.57	0.535	—
	1254			1400		368	0.267	0.42	0	270	5.1	50	14.4	—	—	—	2770	—	—	—	1.57	[illegible]	—
	1305			1345		368	0.267	0.42	0	210	5.1	50	14.4	—	—	—	3000	—	—	—	1.57	0.252	—
	1312			1290		368	0.267	0.42	0	200	5.1	50	14.4	—	—	—	2950	—	—	—	1.57	0.269	—
	[illegible]			[illegible]		368	0.267	0.42	0	310	5.1	50	14.4	—	—	—	2940	—	—	—	1.57	0.416	—
	1335			—		368	0.256	0	0	715	5.0	50	14.4	—	—	—	3020	—	—	—	0	1.0	—
4-26-77	1042	ILL.	conc'c	1750		362	0.275	0	0	750	5.0	50	14.4	4.17	—	—	[illegible]	—	—	—	0	1.0	—
	1105					362	0.275	0.136	0	530	4.7	50	14.4	1.3	—	—	3300	*	*	10	0.457	0.68	—
	1125					362	0.275	0.278	0	380	4.7	50	14.4	41.5	—	—	3100	*	*	10	1.02	0.455	—
	1150					362	0.275	0.352	0	350	5.2	50	13.5	72.0	—	—	[illegible]	*	*	10	1.28	0.45	—
	1210					362	0.275	0.445	0	300	5.0	50	14.0	157	—	—	3140	*	*	12	1.61	[illegible]	—
	1230					362	0.279	0	0	770	5.2	50	14.0	—	—	—	2950	—	—	—	0	1.0	—
	1235			↓		362	0.279	0.455	0	300	5.0	50	14.0	—	—	—	2910	—	—	—	1.63	0.35	—
	1238			1825		362	0.279	0.455	0	240	5.2	50	14.0	—	—	—	3020	—	—	—	1.63	0.304	—
	1241			[illegible]		362	0.279	0.455	0	250	5.3	50	14.0	—	—	—	[illegible]	—	—	—	1.63	0.317	—
	1244			1820		362	0.279	0.455	0	400	5.1	50	14.0	—	—	—	2930	—	—	—	1.63	0.505	—
	1247			[illegible]		362	0.279	0.455	0	560	5.1	50	14.0	—	—	—	2978	—	—	—	1.63	0.71	—
	1250			[illegible]		362	0.279	0.455	0	660	5.1	50	14.0	—	—	—	2880	—	—	—	1.63	0.895	—

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{N_2}{NH_3}$
4-27-77	1100	Ill.	coal	—		362	0.216	0	0	610	5.4	50	14.0	3.64	—	—	3440	*	*	16	0	1.6	—
	1315			—		362	0.267	0	0	760	4.8	50	14.7	2.07	—	—	2950	*	*	16	0	1.6	—
	1425			[illegible]		362	0.279	0.283	0	230	4.5	50	14.7	21.6	—	—	3400	*	*	16	1.00	0.291	—
	1600			[illegible]		362	0.279	0.283	0	240	4.5	50	14.7	57.5	—	—	2900	*	*	16	[illegible]	0.304	—
4-28-77	1145	Ill.	coal	[illegible]		360	0.285	0	0	510	5.4	50	13.8	—	—	—	—	—	—	—	0	1.6	—
	1205			↓		360	0.285	0.132	0	480	5.4	50	13.8	2.67	4.79	12.17	—	—	—	—	0.463	0.57	—
	1225			↓		360	0.285	0.283	0	330	5.3	50	13.5	2.92	3.14	12.4	2950	*	*	6	0.995	0.409	—
	1245			↓		360	0.285	0.355	0	220	4.8	50	14.4	15.2	1.84	13.23	3010	*	*	6	1.25	[illegible]	—
	1255			↓		360	0.285	0.448	0	160	5.2	50	14.0	49.1	0.6	12.1	2976	*	*	8	1.57	0.198	—
4-27-77	[illegible]	Ill.	coal	[illegible]		[illegible]	0.251	0	0	715	5.5	50	13.8	5.11	1.79	12.57	[illegible]	*	*	8	0	1.6	—
	1120			↓		360	[illegible]	0	0	735	5.3	50	14.0	—	—	—	[illegible]	—	—	—	0	1.6	—
	1135			↓		360	0.258	[illegible]	0	500	5.0	50	14.4	7.4	4.53	11.52	[illegible]	*	*	5	[illegible]	[illegible]	—
	1155			↓		[illegible]	0.258	[illegible]	0	320	5.41	50	14.6	34.41	5.72	8.51	[illegible]	*	*	16	1.11	0.415	—
	1215			↓		360	0.255	0.316	0	255	5.3	50	13.6	47.4	6.5	16.22	4950	*	*	12	1.29	0.347	—
	1245			↓		360	0.255	[illegible]	0	210	5.1	50	14.0	51.2	[illegible]	16.8	[illegible]	*	*	12	1.54	[illegible]	—
	1300			[illegible]		360	0.255	[illegible]	0	180	5.4	50	14.0	—	—	—	—	—	—	—	1.54	[illegible]	—
	1301			[illegible]		[illegible]	0.255	[illegible]	0	250	5.3	50	14.0	—	—	—	—	—	—	—	1.54	0.34	—
	1308			[illegible]		360	0.258	[illegible]	0	355	5.3	50	14.0	—	—	—	—	—	—	—	1.54	[illegible]	—
	1312			1795		[illegible]	0.255	[illegible]	0	450	5.2	50	14.0	—	—	—	—	—	—	—	1.64	[illegible]	—
	1315			—		360	0.258	0	0	755	5.2	50	14.0	—	—	—	2810	—	—	—	0	1.6	—

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios NH_3/NO_0	NO/NO_0	N_2/NH_3
5-16-77	1255	PITT.	coal 8	—		360	0.227	0	0	550	5.5	50	14.4	6.12	3.47	12.7	716	—	—	—	0	1.0	—
	1305			—		360	0.228	0	0	570	4.9	50	14.4	—	—	—	760	610	650	6	0	1.3	—
	1325			—		360	0.237	0	0	565	5.0	55	14.4	—	—	—	1038	—	—	—	0	1.6	—
	1355			1520		360	0.233	0.137	0	545	4.7	110	14.4	92	1.52	12.3	1125	510	530	15	.587	0.81	—
	1412			1510		360	0.237	0.234	0	[illegible]	5.2	150	14.4	225	3.42	12.	[illegible]	—	—	12.	1.0	0.67	—
	1437			1525		[illegible]	0.233	0.322	0	[illegible]	5.0	50	14.4	449	7.84	13.5	—	432	452	12.5	1.31	0.62	—
	1503			1525		[illegible]	0.233	0.324	0	402	5.1	150	14.4	477	9.12	12.6	760	—	—	11	1.55	0.60	—
	1540					360	0.245	0	0	722	5.1	50	14.4	—	—	—	1155	665	655	11	0	1.6	—
5-17-77	1016	PITT.	coal 8	—		360	0.231	0	0	630	5.6	50	14.0	5.2	3.37	7.4	1170	630	650	1	0	1.0	—
	1112			—		[illegible]	0.245	0	0	700	5.2	50	14.4	—	—	—	1257	—	—	—	0	1.6	—
	1125			1675		[illegible]	0.245	0.4	0	330	5.2	50	14.4	17.7	2.19	8.0	1275	355	315	1	0.528	0.508	—
	1145			1690		350	0.245	0.239	0	240	5.3	160	14.4	18.5	2.97	11.2	1610	—	—	12	0.974	0.215	—
	1215			1705		[illegible]	0.245	0.378	0	185	5.1	160	14.4	212	[illegible]	12.1	1213	—	—	12	1.54	0.157	—
	1235			1725		360	[illegible]	0.315	0	150	5.3	160	14.4	142.4	6.21	11.2	1105	—	—	10	1.25	0.125	—
5-18-77	1015	PITT.	coal 8	—		360	0	0	0	725	5.1	50	14.7	[illegible]	5.1	8.5	1124	—	—	12	0	1.6	—
	1057			—		[illegible]	0.219	0	0	760	5.1	50	14.7	—	—	—	1105	—	—	—	0	1.6	—
	1105			1730		360	0.257	0.146	0	455	4.7	80	14.7	5.35	2.7	3.4	1110	—	—	16	0.568	0.57	—
	1120			1750		360	0.257	[illegible]	0	305	4.9	150	14.7	40.1	1.6	16.7	1111	—	—	16	1.6	0.41	—
	1140			1760		[illegible]	0.257	0.325	0	240	4.7	160	14.7	54.3	5.5	16.6	1131	—	—	16	1.26	0.274	—
	1200			1770		360	[illegible]	0.37	0	155	4.9	160	[illegible]	111.4	6.5	12.4	1120	—	—	5	1.5	0.212	—
	1215			—		360	0	0	0	725	5.0	50	14.7	—	—	—	1145	—	—	16	0	1.0	—
5-24-77	1255	P.TT.	coal 8	—		364	0.256	0	0	720	5.8	56	14.4	3.77	7.26	7.5	—	—	—	—	0	1.0	—
	1235			—		364	0.257	0	0	725	5.7	56	14.4	—	—	—	—	—	—	—	0	1.0	—
	1245			1830		[illegible]	0.257	0.145	0	530	5.6	50	3.8	2.26	7.41	6.27	—	—	—	—	0.559	0.73	—
	1300			1860		364	[illegible]	0.251	0	415	5.5	50	13.8	3.87	6.4	6.37	—	—	—	—	0.761	0.545	—
	1320			1860		364	0.257	0.327	0	330	5.3	50	14.1	16.6	3.14	3.52	—	—	—	—	1.26	0.452	—
	1340			1870		364	0.257	0.381	0	280	5.4	50	14.1	30.2	3.26	8.55	—	—	—	—	1.49	0.384	—
	1420			—		364	0	0	0	720	5.5	[illegible]	14.1	—	—	—	—	—	—	—	0	1.0	—

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios NH_3/NO_0	NO/NO_0	N_2/NH_3
5-25-77	1045	PITT.	sea. 8	—		365	0.285	0	0	800	4.5	50	14.7	3.4	3.59	22.7	—	—	—	—	0	1.0	—
	1100			—		365	0.272	0	0	720	4.9	50	14.7	—	—	—	—	—			0	1.0	—
	1110			1675		365	0.275	0.127	0	600	4.9	50	14.7	1.65	3.2	21.5	—	—	—	—	0.457	0.77	—
	1130			1693		365	[illegible]	0.251	0	455	4.8	50	14.7	1.76	2.34	[illegible]	—	—	—	—	[illegible]	[illegible]	—
	1145			1575		365	[illegible]	0.349	0	350	4.7	50	14.7	1.66	2.97	5.14	1160	—	—	—	1.25	0.45	—
	1215			1910		365	0.278	[illegible]	0	310	4.8	50	14.7	2.36	3.74	[illegible]	1157	—	—	—	1.45	0.578	—
	1222			1905		365	0.275	[illegible]	0	200	4.7	50	14.7	—	—	—	1130	—	—	—	1.45	0.715	—
	1225			1925		365	[illegible]	0.405	0	210	4.7	50	14.7	—	—	—	1137	—	—	—	1.45	0.269	—
	1227			1815		365	0.278	0.405	0	170	4.7	50	14.7	—	—	—	1127	—	—	—	1.45	0.215	—
	1236			1755		365	0.278	0.405	0	150	4.9	100	14.7	—	—	—	1111	—	—	—	1.45	0.192	—
	1230			[illegible]		365	0.278	0.405	0	250	4.9	100	14.7	—	—	—	1115	—	—	—	1.45	0.32	—
	1335			—		365	0.285	0	0	[illegible]	[illegible]	50	14.7	—	—	—	1160				0	1.0	—
5-26-77	1010	PITT.	sea. 8	—		364	0.224	0	0	[illegible]	4.8	50	14.7	113	—	—	1115	680	690	12	0	1.0	—
	1145			—		364	0.229	0	0	810	4.7	50	15.0	124	—	—	1135	730	730	2	0	1.0	—
	1250			1740		364	0.235	0.252	0	300	4.9	100	14.7	17.8	—	—	1160	220	230	6	1.04	0.305	—
	1255			1770		364	[illegible]	[illegible]	0	310	4.7	100	14.7	9.7	—	—	1215	[illegible]	[illegible]	6	1.04	0.379	—
5-31-77	1430	PITT.	sea. 8	—		362	0.233	0	0	[illegible]	5.1	150	14.4	5.4	—	—	1329	—	—	3	0	1.0	—
	1455			1675		362	0.235	0.311	0	440	5.4	275	14.1	157	—	—	1277	—	—	4	1.32	0.162	—
	1505			1675		362	0.235	0.311	0.042	370	5.1	250	14.1	141	—	—	1254	—	—	4	1.32	0.456	0.135
	1512			1680		362	[illegible]	0.441	0	350	5.1	275	14.1	220	—	—	1264	—	—	4	1.84	0.526	—
	1520			1610		362	0.235	0.441	[illegible]	230	4.9	250	14.1	[illegible]	—	—	1265	—	—	4	1.84	0.391	0.141
	1535			1695		362	0.231	1.03	0	140	5.0	250	14.1	—	—	—	1115	—	—	—	4.36	0.255	0
	1545			1700		362	0.231	0	0	650	4.9	150	14.1	—	—	—	[illegible]	—	—	—	0	1.0	0
	1550			1700		362	0.231	0.311	0	355	4.8	250	14.1	—	—	—	1226	—	—	—	1.3	0.522	0
	1557			[illegible]		[illegible]	[illegible]	0.311	0.042	310	4.9	250	14.1	—	—	—	1217	—	—	—	1.3	0.455	[illegible]
	1555			[illegible]		[illegible]	0.231	0.311	0.100	295	5.0	200	14.1	—	—	—	1205	—	—	—	1.3	0.431	[illegible]
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	0.171	[illegible]	[illegible]	[illegible]	14.1	—	—	—	[illegible]	—	—	—	1.3	0.441	0.55
	1600			1710		362	0.231	0.443	0	305	4.9	250	14.1	—	—	—	[illegible]	—	—	—	1.85	0.441	0
	1602			1710		362	0.237	0.443	0.071	230	5.1	250	14.1	—	—	—	1212	—	—	—	1.85	0.375	0.161
	1624			1715		362	0.237	0.443	0.177	225	5.1	[illegible]	14.1	—	—	—	1210	—	—	—	1.93	0.331	[illegible]
	1636			1715		362	0.237	0.471	0.307	350	4.9	100	14.1	—	—	—	1216	—	—	—	1.96	0.514	0.655
	1655			1715		362	0.239	0.463	0.414	245	5.0	200	14.1	—	—	—	1212	—	—	—	1.93	0.353	0.095
	1720			1721		362	0	0	0	460	5.2	70	14.1	—	—	—	1150	—	—	—	0	1.0	0

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios $\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{H_2}{NH_3}$
5-27-77	1130	ILL.	conic	—		364	0.248	0	0	700	4.8	50	14.7	—	—	—	3050	—	—	—	0	1.0	—
	1132			1650		364	0.245	0.119	0	470	4.9	60	14.7	—	—	—	3060	—	—	—	0.591	0.67	—
	1134			1150		364	0.248	0.117	0	450	4.9	60	14.7	—	—	—	3050	—	—	—	0.591	0.645	—
	1136			[illegible]		364	0.248	0.119	0	450	4.8	50	14.7	—	—	—	3540	—	—	—	0.591	0.645	—
	1138			[illegible]		364	[illegible]	0.119	0	475	4.8	50	14.7	—	—	—	3050	—	—	—	0.591	0.67	—
	1140			[illegible]		364	[illegible]	0.117	0	500	4.8	50	14.7	—	—	—	3040	—	—	—	0.591	0.715	—
	1142			[illegible]		364	0.248	0.119	0	550	4.8	50	14.7	—	—	—	3010	—	—	—	0.591	0.785	—
	1200			[illegible]		364	0.248	[illegible]	0	415	4.7	50	14.7	—	—	—	3010	—	—	—	1.15	0.57	—
	1202			1900		364	[illegible]	0.286	0	395	4.8	50	14.7	—	—	—	2900	—	—	—	1.15	0.495	—
	1204			[illegible]		364	[illegible]	0.286	0	280	4.7	50	14.7	—	—	—	—	—	—	—	1.15	0.4	—
	1206			1315		364	[illegible]	[illegible]	0	240	4.8	50	14.7	—	—	—	—	—	—	—	1.5	0.343	—
	1208			1700		364	[illegible]	[illegible]	0	[illegible]	[illegible]	50	14.7	—	—	—	—	—	—	—	1.5	0.37	—
	1210			[illegible]		364	0.248	[illegible]	0	325	[illegible]	[illegible]	14.7	—	—	—	[illegible]	—	—	—	1.5	0.455	—
	1218			1650		364	[illegible]	[illegible]	0	[illegible]	[illegible]	60	14.7	—	—	—	[illegible]	—	—	—	1.3	0.4	—
	1220			[illegible]		364	[illegible]	[illegible]	0	[illegible]	[illegible]	60	14.7	—	—	—	[illegible]	—	—	—	1.3	0.285	—
	1222			1515		364	0.245	[illegible]	0	175	4.7	60	14.7	—	—	—	[illegible]	—	—	—	1.3	0.243	—
	1224			[illegible]		364	0.248	[illegible]	0	195	4.6	[illegible]	14.7	—	—	—	[illegible]	—	—	—	1.3	0.272	—
	1226			[illegible]		364	[illegible]	[illegible]	0	[illegible]	4.8	[illegible]	14.7	—	—	—	[illegible]	—	—	—	1.3	0.357	
	1228			[illegible]		364	[illegible]	[illegible]	0	[illegible]	[illegible]	50	14.7	—	—	—	3016	—	—	—	1.3	0.415	—
	1230			[illegible]		364	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	14.7	—	—	—	[illegible]	—	—	—	1.59	0.343	—
	1232			1315		364	0.248	[illegible]	0	165	[illegible]	50	14.7	—	—	—	[illegible]	—	—	—	1.59	0.285	—
	1234			[illegible]		364	[illegible]	[illegible]	0	120	4.8	70	14.7	—	—	—	[illegible]	—	—	—	1.59	0.171	—
	1236			1750		364	0.245	[illegible]	0	125	[illegible]	[illegible]	14.7	—	—	—	3010	—	—	—	1.59	0.171	—
	1238			1700		364	[illegible]	[illegible]	0	150	[illegible]	[illegible]	14.7	—	—	—	[illegible]	—	—	—	1.59	0.215	—
	1246			[illegible]		364	0.245	[illegible]	0	220	4.8	[illegible]	14.7	—	—	—	[illegible]	—	—	—	1.59	0.315	—

Test Date	Time	Primary		Centerline		Flow Rates (scfm)				Stack Emissions											Molar Ratios		
										Dry							Wet						
		Fuel	Type	Gas	Temp	Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_3 ppm	SO_2 ppm	NO ppm	NOx ppm	UHC ppm	$\frac{NH_3}{NO_0}$	$\frac{NO}{NO_0}$	$\frac{N_2}{NH_3}$
6-1-77	1433	Pitt.	Seam 8	—		325	0.206	0	0	555	4.9	120	14.1	—	—	—	1180	—	—	—	0	1.0	—
	1443			1275		325	0.206	0.202	0	560	4.8	120	14.1	—	—	—	1205	—	—	—	0.985	0.810	—
	1445			1310		325	0.206	0.202	0	555	4.8	120	14.1	—	—	—	1181	—	—	—	0.985	0.846	—
	1447			1365		325	0.206	0.202	0	500	4.8	120	14.1	—	—	—	1180	—	—	—	0.985	0.846	—
	1449			1410		325	0.206	0.202	0	500	4.8	120	14.1	—	—	—	1164	—	—	—	0.985	0.840	—
	1451			1470		325	0.206	0.202	0	520	4.8	120	14.1	—	—	—	1150	—	—	—	0.985	0.803	—
	1453			1500		325	0.206	0.202	0	490	4.8	120	14.1	—	—	—	1178	—	—	—	0.985	0.765	—
	1455			1535		325	0.206	0.202	0.045	410	4.8	150	14.1	—	—	—	1175	—	—	—	0.985	0.618	0.2
	1457			1500		325	0.206	0.202	0.045	405	4.8	150	14.1	—	—	—	1175	—	—	—	0.985	0.770	0.2
	1459			1445		325	0.206	0.202	0.045	520	4.8	120	14.1	—	—	—	1155	—	—	—	0.985	0.750	0.2
	1501			1465		325	0.206	0.202	0.045	535	4.8	120	14.1	—	—	—	1155	—	—	—	0.985	0.795	0.2
	1503			1500		325	0.201	0.202	0.045	535	4.8	120	14.1	—	—	—	1152	—	—	—	0.985	0.775	0.2
	1505			1310		325	0.211	0.202	0.045	500	4.8	160	14.1	—	—	—	1166	—	—	—	0.985	0.813	0.2
	1506			1310		325	0.201	0.202	0.095	500	4.8	160	14.1	—	—	—	1149	—	—	—	0.985	0.843	0.47
	1508			1350		325	0.204	0.202	0.095	520	4.8	120	14.1	—	—	—	1122	—	—	—	0.985	0.750	0.47
	1510			1415		325	0.201	0.202	0.095	500	4.8	120	14.1	—	—	—	1112	—	—	—	0.985	0.751	0.47
	1512			1460		325	0.202	0.202	0.095	450	4.7	120	14.1	—	—	—	1122	—	—	—	0.985	0.677	0.47
	1514			1525		325	0.206	0.202	0.095	400	4.7	150	14.1	—	—	—	1128	—	—	—	0.985	0.602	0.47
	1516			1510		325	0.206	0.202	0.095	310	4.7	150	14.1	—	—	—	1133	—	—	—	0.985	0.541	0.47
	1517			1570		325	0.201	0.202	0.148	330	4.7	150	14.1	—	—	—	1134	—	—	—	0.985	[illegible]	0.735
	1518			1520		325	0.201	0.202	0.148	365	4.7	150	14.1	—	—	—	1145	—	—	—	0.985	0.555	0.735
	1519			1470		325	0.201	0.202	0.148	420	4.7	120	14.1	—	—	—	1133	—	—	—	0.985	0.635	0.735
	1520			1440		325	0.206	0.202	0.148	440	4.7	120	14.1	—	—	—	1149	—	—	—	0.985	0.669	0.735
	1521			1385		325	0.206	0.202	0.148	470	4.7	120	14.1	—	—	—	1143	—	—	—	0.985	0.746	0.735
	1522			1325		325	0.206	0.202	0.148	500	4.7	120	14.1	—	—	—	1117	—	—	—	0.985	0.752	0.735
	1523			1320		325	0.201	0.207	0.191	470	4.6	120	14.1	—	—	—	1106	—	—	—	0.985	0.735	0.94
	1524			1310		325	0.201	0.207	0.191	465	4.6	120	14.1	—	—	—	1077	—	—	—	0.985	0.710	0.94
	1525			1435		325	0.206	0.207	0.191	400	4.7	150	14.1	—	—	—	1154	—	—	—	0.985	0.616	0.94
	1526			1475		325	0.201	0.207	0.191	310	4.6	150	14.1	—	—	—	1152	—	—	—	0.985	0.555	0.94
	1527			1540		325	0.201	0.207	0.191	250	4.5	150	14.1	—	—	—	1116	—	—	—	0.985	0.440	0.94
	1528			1610		325	0.201	0.207	0.191	[illegible]	4.5	150	14.1	—	—	—	1118	—	—	—	0.985	0.478	0.94
	1529			1610		325	0.201	0.207	0.243	[illegible]	4.7	150	14.1	—	—	—	1143	—	—	—	0.985	0.477	1.17
	1530			1550		325	0.201	0.201	0.243	[illegible]	4.7	150	14.1	—	—	—	1144	—	—	—	0.985	[illegible]	1.17
	1531			1425		325	0.206	0.207	0.243	370	4.7	150	14.1	—	—	—	1133	—	—	—	0.985	[illegible]	1.17
	1532			1415		325	0.201	0.207	0.243	370	4.7	120	14.1	—	—	—	1153	—	—	—	0.985	0.560	1.17
	1533			1380		325	0.206	0.207	0.243	416	4.7	120	14.1	—	—	—	1144	—	—	—	0.985	0.635	1.17
	1534			1325		325	0.206	0.207	0.243	420	4.7	120	14.1	—	—	—	1127	—	—	—	0.985	0.645	1.17

CONT.

KVB

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{H_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_2 ppm	Wet SO_2 ppm	NO ppm	NOx ppm	UHC ppm	Molar Ratios NH_3/NO_0	NO/NO_0	H_2/NH_3
6-1-77	1540	PITT	coni's	1330		325	[illegible]	0.257	0	555	4.7	120	14.1	—	—	—	[illegible]	—	—	—	[illegible]	[illegible]	0
	1547			1330		325	[illegible]	0.311	0	[illegible]	4.7	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	0
	1549			[illegible]		[illegible]	[illegible]	0.311	0	[illegible]	4.8	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	0
	[illegible]			1450		325	[illegible]	0.311	0	[illegible]	4.5	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	0
	[illegible]			[illegible]		325	[illegible]	0.311	0	[illegible]	[illegible]	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	0
	[illegible]			1560		[illegible]	0.266	0.311	0	[illegible]	[illegible]	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	0
	[illegible]			[illegible]		325	[illegible]	0.311	0	[illegible]	4.8	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	0
	[illegible]			[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4.9	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	[illegible]			[illegible]		[illegible]	0.266	0.311	[illegible]	[illegible]	4.9	[illegible]	14.4	—	—	—	[illegible]				1.51	[illegible]	[illegible]
	[illegible]			[illegible]		[illegible]	[illegible]	0.311	[illegible]	[illegible]	[illegible]	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1558			[illegible]		325	[illegible]	0.311	[illegible]	[illegible]	4.7	150	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1559			[illegible]		[illegible]	[illegible]	0.311	[illegible]	[illegible]	4.8	155	14.4	—	—	—	[illegible]		—	—	1.51	[illegible]	[illegible]
	[illegible]			1340		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4.8	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	[illegible]			[illegible]		325	[illegible]	0.311	[illegible]	[illegible]	[illegible]	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1602			1375		[illegible]	[illegible]	0.311	[illegible]	[illegible]	4.7	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1603			1465		[illegible]	[illegible]	0.311	[illegible]	[illegible]	4.9	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	[illegible]			1510		[illegible]	[illegible]	0.311	[illegible]	[illegible]	4.8	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1605			[illegible]		325	[illegible]	0.311	[illegible]	[illegible]	4.8	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1606			1610		[illegible]	[illegible]	0.311	[illegible]	[illegible]	4.5	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1607			[illegible]		325	[illegible]	0.311	[illegible]	[illegible]	4.4	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1608			1530		325	[illegible]	0.311	[illegible]	[illegible]	4.4	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1609			1515		[illegible]	[illegible]	0.311	[illegible]	[illegible]	4.4	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1610			[illegible]		[illegible]	[illegible]	0.311	[illegible]	[illegible]	4.4	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1611			1410		[illegible]	0.266	0.311	[illegible]	350	4.4	150	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1612			1350		325	[illegible]	0.311	[illegible]	[illegible]	4.5	[illegible]	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	[illegible]
	1613			[illegible]		[illegible]	[illegible]	0.311	0	[illegible]	4.5	200	14.4	—	—	—	[illegible]	—	—	—	1.51	[illegible]	0
	1616			—		[illegible]	0	0	0	[illegible]	4.7	155	14.4	—	—	—	[illegible]	—	—	—	0	1.0	0
	1625			—		[illegible]	0	0	0	[illegible]	4.7	[illegible]	14.4	—	—	—	[illegible]	—	—	—	0	1.0	0
6-2-77	1115	PITT	coni's	—		326	0.267	0	0	[illegible]	5.0	150	14.4	6.8	[illegible]	9.46	[illegible]	—	—	—	0	1.0	0
	1130			—		326	[illegible]	0	0	[illegible]	5.0	150	14.4	—	—	—	[illegible]	—	—	—	0	1.0	0
	1145			1395		326	[illegible]	0.310	0	[illegible]	4.9	[illegible]	14.4	[illegible]	16.1	17.3	[illegible]	—	—	—	1.49	[illegible]	0
	1202			1465		326	[illegible]	0.310	.043	[illegible]	4.8	[illegible]	14.4	[illegible]	19.3	[illegible]	[illegible]	—	—	—	1.49	[illegible]	[illegible]
	1225			1420		326	[illegible]	0.310	[illegible]	510	4.8	250	14.4	[illegible]	15.6	14.4	[illegible]	—	—	—	1.49	[illegible]	[illegible]
	[illegible]			1425		[illegible]	[illegible]	0.318	[illegible]	[illegible]	4.5	[illegible]	14.4	[illegible]	[illegible]	[illegible]	[illegible]	—	—	—	1.52	[illegible]	[illegible]
	[illegible]			1435		326	[illegible]	0.318	[illegible]	290	4.5	[illegible]	14.4	[illegible]	[illegible]	12.7	[illegible]	—	—	—	1.52	[illegible]	[illegible]
	[illegible]			1445		[illegible]	[illegible]	0.318	[illegible]	330	4.7	200	14.4	[illegible]	[illegible]	[illegible]	[illegible]	—	—	—	1.52	[illegible]	[illegible]
	1340			1450		326	[illegible]	0	0	550	4.9	150	[illegible]	—	—	—	[illegible]	—	—	—	0	1.0	0

C-33

KVB

Test Date	Time	Primary Fuel	Primary Type	Centerline Gas	Centerline Temp	Flow Rates (scfm) Q_{Air}	Q_{NO}	Q_{NH_3}	Q_{N_2}	Stack Emissions Dry NO ppm	O_2 pct	CO ppm	CO_2 pct	NH_3 ppm	HCN ppm	NO_2 ppm	Wet NO_x ppm	NO ppm	HCN ppm	UHC ppm	Molar Ratios NH_3/NO_o	NO/NO_o	N_2/NH_3
6-3-77	1227	PITT.	[illegible]	1340		327	.198	.299	0	[illegible]	5.2	225	14.1	—	—	—	1100	—	—	—	1.5	[illegible]	0
	1242			1405					0	475	5.25	[illegible]	14.1	—	—	—	[illegible]	—	—	—		.79	0
	1245			1475					0	475	5.3	240	14.1	—	—	—	1640	—	—	—		[illegible]	0
	1247			1545					0	[illegible]	5.25	[illegible]	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1249			[illegible]					0	385	5.25	240	14.1	—	—	—	[illegible]	—	—	—		.614	0
	1250			[illegible]					0	380	5.3	240	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1252			1626				.216	0	[illegible]	5.4	[illegible]	14.1	—	—	—	[illegible]	—	—	—	1.09	[illegible]	0
	1255			1615					0	[illegible]	5.3	[illegible]	14.1	—	—	—	[illegible]	—	—	—		.77	0
	1256			[illegible]					0	[illegible]	5.3	[illegible]	14.1	—	—	—	[illegible]	—	—	—		.70	0
	1258			1475					0	[illegible]	[illegible]	[illegible]	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1300			1465					0	[illegible]	5.4	[illegible]	14.1	—	—	—	775	—	—	—		[illegible]	0
	1302			3.0					0	[illegible]	5.2	[illegible]	14.1	—	—	—	762	—	—	—		[illegible]	0
	1340			—		364	.34	0	0	[illegible]	5.3	225	14.1	—	—	—	[illegible]	—	—	—	0	1.0	0
	1352			[illegible]				.324	0	[illegible]	5.1	255	14.1	—	—	—	[illegible]	—	—	—	1.35	[illegible]	0
	[illegible]			1575					0	[illegible]	5.2	[illegible]	14.1	—	—	—	[illegible]	—	—	—		.76	0
	[illegible]			1625					0	[illegible]	5.1	[illegible]	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	[illegible]			1890					0	[illegible]	5.15	[illegible]	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1402			1740					0	[illegible]	5.1	[illegible]	14.1	—	—	—	[illegible]	—	—	—		.341	0
	1404			[illegible]					0	[illegible]	5.1	280	14.1	—	—	—	[illegible]	—	—	—		.295	0
	1405			1775				.431	0	[illegible]	4.95	275	14.1	—	—	—	[illegible]	—	—	—	1.5	.171	0
	1408			1740					0	[illegible]	5.0	[illegible]	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1410			1690					0	335	5.0	275	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1412			1655					0	[illegible]	5.3	275	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1414			1650					0	[illegible]	[illegible]	[illegible]	14.1	—	—	—	[illegible]	—	—	—		[illegible]	0
	1419			1525					0	[illegible]	5.2	[illegible]	14.1	—	—	—	[illegible]	—	—	—		.515	0
6-6-77	[illegible]	[illegible]	[illegible]	—		[illegible]	.195	0	0	[illegible]	[illegible]	[illegible]	14.7	10	.52	10.8	[illegible]	—	—	—	0	1.0	0
	[illegible]			[illegible]		327	[illegible]	[illegible]	0	[illegible]	[illegible]	[illegible]	14.7	356	7.76	11.7	[illegible]	—	—	—	1.59	[illegible]	0
	1212			1550		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4.4	[illegible]	5.0	324	13.3	14.9	[illegible]	—	—	—	1.57	[illegible]	[illegible]
	1230			[illegible]		327	.195	[illegible]	[illegible]	[illegible]	4.2	273	5.0	221	14.8	13.6	[illegible]	—	—	—	1.59	[illegible]	[illegible]
	1300			[illegible]		327	[illegible]	.305	[illegible]	344	4.7	250	14.7	51	13.5	11.7	[illegible]	—	—	—	1.56	[illegible]	[illegible]
	[illegible]			1676		327	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	14.7	69	13.4	13.6	[illegible]	—	—	—	1.63	[illegible]	[illegible]
	1327			—		327	0	0	0	625	4.9	72	14.7	—	—	—	765	—	—	—	0	1.0	0

APPENDIX D

FUEL ANALYSIS

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

PLEASE ADDRESS ALL CORRESPONDENCE TO
16 [illegible]N DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

SINCE 1908

March 15, 1977

KVB, INC.
17332 Irvine Blvd.
Tustin, CA 92680

Kind of sample reported to us	Coal
Sample taken at	----
Sample taken by	KVB, Inc.
Date sampled	----

Sample identification by
KVB, Inc.
P. O. # 12 121
Project # 15500
P.C 12
Coal sample

Analysis report no. 71-461882

PROXIMATE ANALYSIS	As received	Dry basis
% Moisture	4.24	xxxxx
% Ash	4.85	5.06
% Volatile	36.38	37.99
% Fixed Carbon	54.53	56.95
	100.00	100.00
Btu	13111	13692
% Sulfur	[illegible].54	0.56
% Alk. as Na_2O	xxxxx	1.97
SULFUR FORMS		
% Pyritic Sulfur	0.19	0.20
% Sulfate Sulfur	0.01	0.01
% Organic Sulfur	0.34	0.35
	0.54	0.56
WATER SOLUBLE ALKALIES		
% Na_2O =	xxxxx	xxxxx
% K_2O =	xxxxx	xxxxx

ULTIMATE ANALYSIS	% Weight As received	% Weight Dry basis
Moisture	4.24	xxxxx
Carbon	71.52	74.69
Hydrogen	5.44	5.68
Nitrogen	1.52	1.59
Chlorine	0.01	0.01
Sulfur	0.54	0.56
Ash	4.85	5.06
Oxygen (diff)	11.88	12.41
	100.00	100.00

MINERAL ANALYSIS OF ASH	% Weight Ignited Basis
Silica, SiO_2	60.46
Alumina, Al_2O_3	18.88
Titania, TiO_2	1.10
Ferric oxide, Fe_2O_3	4.60
Lime, CaO	5.30
Magnesia, MgO	0.90
Potassium oxide, K_2O	1.15
Sodium oxide, Na_2O	3.14
Sulfur trioxide, SO_3	3.99
Phos. pentoxide, P_2O_5	0.10
Undetermined	0.38
	100.00

SILICA VALUE = 84.84
BASE: ACID RATIO
T_{250} Temperature = 2890 °F

FUSION TEMPERATURE OF ASH	Reducing	Oxidizing
Initial Deformation	2130 °F	2200 °F
Softening (H = W)	2310 °F	2400 °F
Softening (H = ½W)	2360 °F	2440 °F
Fluid	2700+ °F	2700+ °F

H is Cone Height
W is Cone Width

% EQUILIBRIUM MOISTURE = xx
HARDGROVE GRINDABILITY INDEX = xx
FREE SWELLING INDEX = xx

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

R. A. HOUSER, Manager Midwest Division

D-2

RAH:hs

AMERICAN COUNCIL OF INDEPENDENT LABORATORIES INC.
Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

E ADDRESS ALL CORRESPONDENCE TO
AN DRUMEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

SINCE 1908

April 20, 1977

KVB, INC.
1306 E. Edinger
Suite B
Santa Ana, CA 92705

Kind of sample reported to us: Coal

Sample taken at: ----

Sample taken by: KVB, INC.

Date sampled: ----

Sample identification by:
KVB, INC.
P. O. # 12311
Project # 15500
P.C. 12
Utah Coal "A"
Taken: 1340 Hrs. 3-23-77

Analysis report no. 71-458638

SULFUR FORMS

	Dry
Pyritic Sulfur	0.15
Sulfate Sulfur	0.00
Organic Sulfur(dif)	0.38
Total Sulfur	0.53

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

R. A. HOUSER Manager Midwest Division

RAH:hs

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

PLEASE ADDRESS ALL CORRESPONDENCE TO
1 'AN BRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 6047

OFFICE TEL (312) 264-117

SINCE 1908

April 20, 1977

KVB, INC.
1306 E. Edinger
Suite B
Santa Ana, CA 92705

Kind of sample reported to us: Coal

Sample taken at: ----

Sample taken by: KVB, INC.

Date sampled: ----

Sample identification by:
KVB, INC.
P. O. # 12311
Projcet # 15500
P.C. 12
Utah Coal "A"
Taken 1520 Hrs. 3-23-77

Analysis report no. 71-458639

SULFUR FORMS

	Dry
Pyritic Sulfur	0.12
Sulfate Sulfur	0.00
Organic Sulfur(dif)	0.42
Total Sulfur	0.54

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

R A HOUSER Manager Midwest Division
RAH:hs

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

E ADDRESS ALL CORRESPONDENCE TO
AN DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

SINCE 1908

April 20, 1977

KVB, INC.
1306 E. Edinger
Suite B
Santa Ana, CA 92705

Sample identification by

KVB, INC.
P. O. # 12311
Project # 15500
P.C. 12
Utah Coal "A"
Sample taken 1000 Hrs. 3-24-77

Kind of sample reported to us Coal

Sample taken at ——

Sample taken by KVB, INC.

Date sampled ——

Analysis report no. 71-458640

SULFUR FORMS

	Dry
Pyritic Sulfur	0.08
Sulfate Sulfur	0.00
Organic Sulfur (dif)	0.46
Total Sulfur	0.54

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

R A HOUSER Manager Midwest Division

RAH:hs

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

PLEASE ADDRESS ALL CORRESPONDENCE TO
[illegible] AN DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

April 20, 1977

KVB, INC.
1306 E. Edinger
Suite B
Santa Ana, CA 92705

Sample identification by
KVB, INC.
P. O. # 12311
Project # 15500
P.C. 12
Utah Coal "A"
Sample taken 1230 hrs. 3-24-77

Kind of sample reported to us: Coal

Sample taken at: ----

Sample taken by: KVB. INC.

Date sampled: ----

Analysis report no. 71-458641

SULFUR FORMS

	Dry
Pyritic Sulfur	0.12
Sulfate Sulfur	0.00
Organic Sulfur(dif)	0.42
Total Sulfur	0.54

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

R A HOUSER Manager Midwest Division

D-6

RAH:hs

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

PLEASE ADDRESS ALL CORRESPONDENCE TO
N DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

SINCE 1908

KVB, INC.
1306 E. Edinger, Suite B
Santa Ana, CA 92705

April 22, 1977

Kind of sample reported to us	Coal
Sample taken at	xxxxx
Sample taken by	KVB, Inc.
Date sampled	4/6/77

Sample Identification by John Arand
"Navaho" Coal B" taken 1130 hrs. on 4/6/77

Analysis report no. 71-458643

PROXIMATE ANALYSIS	As received	Dry basis
% Moisture	8.33	xxxxx
% Ash	17.00	18.54
% Volatile	34.53	37.67
% Fixed Carbon	40.14	43.79
	100.00	100.00
Btu	10336	11275
% Sulfur	0.57	0.62
% Alk. as Na_2O	xxxxx	0.56
SULFUR FORMS		
% Pyritic Sulfur	0.19	0.21
% Sulfate Sulfur	0.00	0.00
% Organic Sulfur	0.38	0.41
WATER SOLUBLE ALKALIES		
% Na_2O =	xxxxx	xxxxx
% K_2O =	xxxxx	xxxxx

ULTIMATE ANALYSIS	% Weight As received	Dry basis
Moisture	8.33	xxxxx
Carbon	57.98	63.25
Hydrogen	4.40	4.80
Nitrogen	1.48	1.61
Chlorine	0.01	0.01
Sulfur	0.57	0.62
Ash	17.00	18.54
Oxygen (diff)	10.23	11.17
	100.00	100.00

MINERAL ANALYSIS OF ASH	% Weight Ignited Basis
Silica, SiO_2	57.53
Alumina, Al_2O_3	26.93
Titania, TiO_2	1.17
Ferric oxide, Fe_2O_3	3.51
Lime, CaO	3.92
Magnesia, MgO	0.98
Potassium oxide, K_2O	0.81
Sodium oxide, Na_2O	2.48
Sulfur trioxide, SO_3	2.20
Phos. pentoxide, P_2O_5	0.09
Undetermined	0.38
	100.00
SILICA VALUE =	87.25
BASE: ACID RATIO	0.14
T_{250} Temperature =	2900+

FUSION TEMPERATURE OF ASH	Reducing	Oxidizing
Initial Deformation	2400	2540
H is Cone Height — Softening (H = W)	2700+	2700+
W is Cone Width — Softening (H = ½W)	2700+	2700+
Fluid	2700+	2700+

% EQUILIBRIUM MOISTURE =	xxxxx
HARDGROVE GRINDABILITY INDEX =	xxxxx
FREE SWELLING INDEX =	xxxxx

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

R. A. HOUSER, Manager Midwest Division

RAH/dh

D-7

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

PI E ADDRESS ALL CORRESPONDENCE TO
1 AN DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

SINCE 1908

April 20, 1977

KVB, INC.
1306 E. Edinger
Suite B
Santa Ana, CA 92705

Sample identification by
KVB, INC.
P. O. # 12311
Project # 15500
P.C. 12
"Navaho B"
Taken: 1000 Hrs. on 4-6-77

Kind of sample reported to us Coal

Sample taken at ——

Sample taken by KVB, INC.

Date sampled ——

Analysis report no. 71-458642

SULFUR FORMS

	Dry
Pyritic Sulfur	0.18
Sulfate Sulfur	0.00
Organic Sulfur(dif)	0.46
Total Sulfur	0.64

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

R A HOUSER Manager Midwest Division

RAH:hs

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

ADDRESS ALL CORRESPONDENCE TO
VAN DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

SINCE 1908

OFFICE TEL. (312) 264-1173

May 25, 1977

KVB, INC.
17332 Irvine Blvd.
Tustin, CA 92680

Kind of sample reported to us	Coal
Sample taken at	----
Sample taken by	KVB, Inc.
Date sampled	4/27/77

Sample Identification by

KVB, Inc.
P. O. # 12393
Project # 15500
Illinois Coal C
Taken 1325 hrs. 4/27/77

Analysis report no. 71-1163

PROXIMATE ANALYSIS	As received	Dry basis
% Moisture	12.02	xxxxx
% Ash	10.24	11.64
% Volatile	33.27	37.81
% Fixed Carbon	44.48	50.55
	100.00	100.00
Btu	10941	12434
% Sulfur	2.94	3.34
% Alk. as Na_2O	xxxxx	0.31

SULFUR FORMS	As received	Dry basis
% Pyritic Sulfur	1.27	1.44
% Sulfate Sulfur	0.06	0.07
% Organic Sulfur	1.61	1.83
	2.94	3.34

WATER SOLUBLE ALKALIES	As received	Dry basis
% Na_2O –	xxxxx	xxxxx
% K_2O –	xxxxx	xxxxx

FUSION TEMPERATURE OF ASH	Reducing	Oxidizing
Initial Deformation	1960°F	2050°F
H is Cone Height — Softening (H = W)	2090°F	2310°F
W is Cone Width — Softening (H = ½W)	2130°F	2360°F
Fluid	2350°F	2500°F

% EQUILIBRIUM MOISTURE = xx
HARDGROVE GRINDABILITY INDEX = xx
FREE SWELLING INDEX = xx

ULTIMATE ANALYSIS (% Weight)	As received	Dry basis
Moisture	12.01	xxxxx
Carbon	60.42	68.67
Hydrogen	4.36	4.95
Nitrogen	1.07	1.22
Chlorine	0.03	0.03
Sulfur	2.94	3.34
Ash	10.24	11.64
Oxygen (diff)	8.93	10.15
	100.00	100.00

MINERAL ANALYSIS OF ASH	% Weight Ignited Basis
Silica, SiO_2	48.93
Alumina, Al_2O_3	17.44
Titania, TiO_2	0.90
Ferric oxide, Fe_2O_3	19.55
Lime, CaO	5.37
Magnesia, MgO	0.99
Potassium oxide, K_2O	2.13
Sodium oxide, Na_2O	1.26
Sulfur trioxide, SO_3	2.85
Phos. pentoxide, P_2O_5	0.25
Undetermined	0.33
	100.00

SILICA VALUE = 65.38
BASE: ACID RATIO 0.44
T_{250} Temperature = 2360°F

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

RAHouser

R. A. HOUSER, Manager Midwest Division

D-9

RAH:hs

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

ADDRESS ALL CORRESPONDENCE TO
161[illegible] VAN DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS [illegible]

OFFICE TEL (312) 264-1173

SINCE 1908

May 20, 1977

KVB, INC.
1306 E. Edinger
Suite B
Santa Ana, CA 92705

Sample identification by

KVB, Inc.
P. O. # 12393
Project # 15500
Illinois Coal C
Taken 1115 hrs on 4/27/77

Kind of sample reported to us: Coal

Sample taken at: ----

Sample taken by: KVB, Inc.

Date sampled: ----

Analysis report no. 71-1164

SULFUR FORMS

	% Wt. - DRY
Pyritic Sulfur	1.40
Sulfate Sulfur	0.09
Organic Sulfur(diff)	2.80
Total Sulfur	4.29

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

R A HOUSER Manager Midwest Division

D-10

RAH:hs

Charter Member

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COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

PLEASE ADDRESS ALL CORRESPONDENCE TO
VAN DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

June 16, 1977

KVB, INC.
1306 E. Edinger, Suite B
Santa Ana, CA 92705

Kind of sample reported to us	-----
Sample taken at	-----
Sample taken by	KVB, Inc.
Date sampled	-----

Sample identification by
KVB, Inc.

Purchase order 12439

Sample: Pittsburgh #8 fired
@1220, 5-26-77

Analysis report no. 71-1836

PROXIMATE ANALYSIS	As received	Dry basis
% Moisture	1.67	xxxxx
% Ash	7.16	7.28
% Volatile	37.13	37.76
% Fixed Carbon	54.04	54.96
	100.00	100.00
Btu	13624	13855
% Sulfur	1.81	1.84
% Alk. as Na_2O	xxxxx	0.10

SULFUR FORMS	As received	Dry basis
% Pyritic Sulfur	0.93	0.95
% Sulfate Sulfur	0.02	0.02
% Organic Sulfur	0.86	0.87

WATER SOLUBLE ALKALIES	As received	Dry basis
% Na_2O =	xxxxx	xxxxx
% K_2O =	xxxxx	xxxxx

FUSION TEMPERATURE OF ASH	Reducing	Oxidizing
Initial Deformation	2120°F	2445°F
Softening (H = W)	2250°F	2520°F
Softening (H = ½W)	2380°F	2600°F
Fluid	2510°F	2635°F

H is Cone Height
W is Cone Width

% EQUILIBRIUM MOISTURE = xxxxx
HARDGROVE GRINDABILITY INDEX = xxxxx
FREE SWELLING INDEX = xxxxx

ULTIMATE ANALYSIS	% Weight As received	% Weight Dry basis
Moisture	1.67	xxxxx
Carbon	76.16	77.45
Hydrogen	5.10	5.19
Nitrogen	1.48	1.51
Chlorine	0.02	0.02
Sulfur	1.81	1.84
Ash	7.16	7.28
Oxygen (diff)	6.60	6.71
	100.00	100.00

MINERAL ANALYSIS OF ASH	% Weight Ignited Basis
Silica, SiO_2	48.04
Alumina, Al_2O_3	24.28
Titania, TiO_2	1.05
Ferric oxide, Fe_2O_3	19.55
Lime, CaO	2.02
Magnesia, MgO	0.64
Potassium oxide, K_2O	1.55
Sodium oxide, Na_2O	0.32
Sulfur trioxide, SO_3	1.41
Phos. pentoxide, P_2O_5	0.31
Undetermined	0.83
	100.00

SILICA VALUE = 68.38
BASE : ACID RATIO 0.33
T_{250} Temperature = 2500°F

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO
RAHouser
R. A. HOUSER Manager Midwest Division

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RAH:ljd

Charter Member

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 228 NORTH LA SALLE STREET, CHICAGO, ILLINOIS 60601 · AREA CODE 312 726-8434

P : ADDRESS ALL CORRESPONDENCE TO
16 VAN DRUNEN ROAD, SOUTH HOLLAND, ILLINOIS 60473

OFFICE TEL (312) 264-1173

SINCE 1908

June 16, 1977

KVB, INC.
1306 E. Edinger, Suite B
Santa Ana, CA 92705

Sample identification by	KVB, Inc. Purchase order 12439 Pittsburgh #8 fired @1010 5/26/77
Kind of sample reported to us	-----
Sample taken at	-----
Sample taken by	KVB, Inc.
Date sampled	-----

Analysis report no. 71-1835

DRY SULFUR FORMS

% Pyritic Sulfur	1.05
% Sulfate Sulfur	0.01
% Organic Sulfur	0.91
% Total Sulfur	1.97

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

R A Houser

R A HOUSER Manager, Midwest Division

RA H:ljd

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Charter Member

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END